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Grid Interactive Microgrid Controllers and the Management of Aggregated Distributed Energy Resources (DER)

Relationship of Microgrid Controller with Distributed Energy Resource Management System (DERMS) and Utility Distributed Management System (DMS)

2015 TECHNICAL REPORT

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Abstract

Over the past few years, industry activities to create standards for distributed energy resources (DER) management systems have primarily focused on the behaviors of individual DER units and open communication protocols over the field networks that connect directly to these devices. To better integrate and manage many diverse distributed resources, EPRI has been developing functional requirements and communication protocols for distributed energy resource management systems (DERMS) operating in a grid-tied mode (EPRI reports 3002002464 and 3002001249). A recent publication from the Argonne National Laboratory provides the guidelines for implementing advanced distribution management systems (DMS). These activities are intended to provide the industry with a point of reference and to provide guidance to research and standards development organizations.

This project described in this report aims to advance the state of the art in microgrids and aggregated DER by developing and defining standardized functions for the microgrid controller. Additionally, the project will establish the roles of microgrid management and DERMS functionalities within the microgrid controller and identify the interface between the microgrid controller and the distribution system operator (DSO) through interaction with the DMS. A key focus is on the overall utility system architecture that describes the high level architecture of microgrid controllers with respect to DMS and DER. The project also identifies architectural variations between DMS, microgrid controllers, DERMS, and DERs.

The document examines the relationship between DER and the microgrid controller/DERMS as well as the relationship between the microgrid controller/DERMS and DMS. The description of the architecture from DER to microgrid controllers/DERMS identifies the interface, messages, information exchanged, communications protocols, and functional requirements for each of the functions that relate DER to microgrid controllers/DERMS. An in-depth discussion of the integration of the microgrid controller/DERMS with DMS is provided. The report also identifies remaining technical gaps in the integration of DMS, DERMS, and microgrid controllers.

Keywords
Microgrid controller
DERMS (distributed energy resource management system)
DMS (distribution management system)

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Section 1: Introduction, Objectives and Approach

1.1 Introduction

Over the past few years, industry activities to create standards for distributed energy resources (DER) management systems have primarily focused on the behaviors of individual DER units[1,2] and open communication protocols over the field networks that connect directly to these devices. To better integrate and manage many diverse distributed resources, EPRI has been developing functional requirements[3,4] and communication protocols for distributed energy resource management systems (DERMS) operating in a grid tied mode. Two recent publications from ANL provide guidelines for implementing advanced distribution management systems (DMS)[5,6]. These activities are intended to provide the industry with a point of reference and to provide guidance to research and standards development organizations.

1.2 Objectives

The project will advance the state-of-the-art in microgrids and aggregated DER by developing and defining standardized functions for the microgrid controller. This project will also establish the roles of microgrid management and DERMS functionalities within the microgrid controller and identifies the interface between the microgrid controller and the distribution system operator (DSO) through interaction with the DMS. The grid interactive microgrid community will help utility grid operators plan for and support local capacity targets of DER

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[1] *Common Functions for Smart Inverters*. EPRI, Palo Alto, CA: 2011. 1023059

[2] *Concepts to Enable Advancement of Distributed Energy Resources*. EPRI, Palo Alto, CA: 2010. 1020432

[3] *Smart Distribution Applications for Distributed Energy Resources: Distribution Management System Use Case*. EPRI, Palo Alto, CA: 2013. 3002002464

[4] *Enterprise Integration Functions for Distributed Energy Resources: Phase 1*. EPRI, Palo Alto, CA: 2013. 3002001249

[5] ANL/ESD-15/15, *Guidelines for implementing advanced DMS: Requirements for DMS integration with DERMS and Microgrids*, ANL Report, August 2015

[6] *Foundational Report Series: Advanced Distribution Management Systems for Grid Modernization; Importance of DMS for Distribution Grid Modernization*. Argonne National Laboratory, Argonne, IL: 2015.

while also achieving objectives for improved operations resiliency. The result can be a modernized distribution grid that uses more optimal methods to meet both local and overall grid operations.

1.3 Approach

This document will develop and define standardized functions for the microgrid controller through a series of tasks described below:

1. The grid interactive microgrid community could help utility grid operators plan for and support local capacity targets of DER while also achieving objectives for improved resiliency. The result can be a modernized distribution grid based that uses more optimal methods to meet both local capacity requirements and overall grid capacity requirements. Identifying and developing use cases provides a foundation for functional requirements and configuration specifications of a microgrid controller that becomes an integral part of overall distribution management.
2. Determine the functions that are required at the distribution management level for the control and interface with microgrids located on the distribution system. These microgrid controller functions and services reflect industry standards and provide a platform for continued innovation. A flexible controller with standard functions and interfaces can expand community opportunities to link local resources with overall grid operation as well as use these resources to operate in islanded mode for improved resiliency.
3. The microgrid controller architecture is based upon a layered strategy for managing and controlling the operations of distributed resources and loads that may be part of local microgrids. The distribution microgrid controller is treated as a separate logical control entity so that the interactions between DER and other utility systems can be identified and supporting functional requirements developed. The coordinated functional requirements for the local microgrid controller will be defined. These functions will include the functions that must be coordinated with the overall management of distributed resources on the distribution system and other functions that must coordinate with the DMS (e.g. voltage control and fault management).

1.3.1 State of the Industry

1.3.1.1 DERMS

Utilities have used DERMS to control and increase flexibility to be able to better manage available resources for an increasingly distributed grid. The primary objective of DERMS is to optimally manage distributed resources on the distribution grid. The resources can be a variety of technologies—such as solar and wind generation, energy storage, demand-response resources, microgrids, electric vehicles, and combined heat and power facilities—that supply or consume energy on the order of magnitude of tens or hundreds of watts to tens of megawatts.[7] The DERMS architecture is based on a layered strategy for enabling distributed wide area controls and services-based models for accessing capabilities and dispatch of DERs. DERMS uses a layered architecture that includes three main levels: DER asset level, master DER controller level, and enterprise level. The enterprise level aggregates all generation, storage and demand resources and provides a single controllable interface for distribution network operators. This enables microgrids capable of rapidly islanding a facility from the power grid for reliability or security purposes and gain active control over power import and export.[8] DERMS is also being used to address the technical and economic challenges associated with the increase in customer-owned distributed resources.[9] Despite being a new and blossoming market, areas with greater renewable generation have seen greater rates of adoption of DERMS technologies and have initiated projects.[10] Utilities are continuing to enhance strategies that include mitigating the technical and economic challenges of the distribution grid, one solution to this being DERMS. Because the capabilities of DERMS are able to address these needs, there has been a large movement toward further development and adoption of the DERMS technology.[11]

1.3.1.2 Microgrid Controller

The functions of a microgrid controller include monitoring and control software, typically SCADA, energy management, generator and load management; system reconfiguration and black start after a fault; system efficiency monitoring; carbon dioxide contribution analysis; and system health monitoring. In addition, it may receive precise weather forecast data from a professional weather service for all locations of renewable power generators inside the microgrid. Merging this information with the physical characteristics of the generators, the microgrid energy manager can predict the available amount of renewable power generation for the near-term. This information helps plan the utilization rate of the fossil-fueled generators within the microgrid.[12] While the number of installed microgrids and subsequent microgrid controllers is considered small, the proliferation of microgrids is growing on a global scale in response to the need to

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[7] *2012 Grid Strategy: Distribution Management System Advanced Applications for Distributed Energy Resources.* EPRI, Palo Alto, CA: 2012. 1025572.

[8] *Smart Distribution Applications for Distributed Energy Resources.* EPRI, Palo Alto, CA: 2013. 070625.

[9] Saadeh, Omar. *A Glimpse Into the DERMS Vendor Ecosystem. https://www.greentechmedia.com/articles/read/a-glimpse-into-the-derms-vendor-ecosystem-and-solutionsSeptember 17, 2014*

[10] Saadeh, Omar. *Distributed Energy Resource Management Systems 2014: Technologies, Deployments and Opportunities.* https://www.greentechmedia.com/research/report/distributed-energy-resource-management-systems-2014 October 7, 2014.

[11] Saadeh, Omar. *Distributed Energy Resource Management Systems 2014: Technologies, Deployments and Opportunities.* https://www.greentechmedia.com/research/report/distributed-energy-resource-management-systems-2014 October 7, 2014.

[12] *Smart Distribution Applications for Distributed Energy Resources.* EPRI, Palo Alto, CA: 2013. 070625.

provide reliable and sustainable service for customers. Microgrids are also seen as a key solution for universal access to energy, specifically in remote locations and/or developing countries. As the drive for efficiency and renewable energy continues to increase so does the prominence of microgrids and microgrid controllers.

This document includes six sections and two appendices:

1. *Introduction, Objectives, and Approach* – presents an overview and goals of the report

2. *Overall Utility System Architecture* – describes the high level architecture of microgrid controllers with respect to DMS and DER. This section also examines architectural variations between DMS, microgrid controllers, DERMS and DERs.

3. *DER to Microgrid Controller/DERMS* – provides a breakdown of the architecture from DER to microgrid controllers/DERMS and identifies the interface, messages, information exchanged, and communications protocols for each of the functions associated with DER to microgrid controllers/DERMS as well as functional requirements.

4. *Microgrid Controller/DERMS to DMS* – Provides a discussion of the relationship between microgrid controllers. DERMS, and DMS as well as an in depth discussion about DMS and its applications, functionality, capabilities, and requirements when integrated with a microgrid controller.

5. *Next Steps* – Provides information about existing gaps and the next steps for the electric power industry.

6. *Conclusion* – Provides concluding remarks for the overall document.

Appendix A Additional requirements for functions

Appendix B CIM messages from test cases

Section 2: Overall Utility System Architecture

Traditional DMS is morphing into an integrated system of systems to accommodate DER through advanced applications within DMS. The applications provide functionality to monitor and control resources and to provide additional grid and workforce optimization tools. Other utilities are looking to deploy separate management systems to manage both DER and demand response resources, typically viewed as a subset of DER.[13] DMS will assume additional operational tasks that involve monitoring and controlling DER and demand response as the smart grid evolves. Outside of the core components, DMS can be viewed as a collection of advanced applications performing grid operational and optimization functions. The functions of advanced applications include monitoring and controlling the distribution system and the connected DER, locating and isolating faults, managing outage restoration, dispatching crews, managing switching, and optimizing the grid. As the number of DER and demand response devices increases, utilities are looking for robust tools to handle the new generation and load control devices being added to the distribution system.[14]

Accurate DER modeling in conjunction with current and past operational characteristic of DER, supports DERMS with DER availability forecasting, to schedule and dispatch DER, and to modify protection schemes. DERMS will be able to provide short-term DER availability along with corresponding feeder and substation load forecasts. This forecasting functionality enables DERMS to schedule and dispatch these distributed energy resources so as to optimize the system. In addition, long-term system planning capabilities provided by DERMS assist planning engineers with running planning studies that include DER. Another planning function includes determining the best protection schemes for the system without and with any combination of DER operating at a given point in time. DERMS can assist with the task of choosing or even changing relay settings based on system conditions, an example of which is a microgrid. The

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[13] *2012 Grid Strategy: Distribution Management System Advanced Applications for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2012. 1025572.

[14] Ibid.

protection scheme may need to be modified depending on whether the microgrid is operating in grid tied or islanded mode.[15]

The general DERMS architecture is consistent with and compatible with the major DER integration applications such as DER energy management, DER firming and smoothing, and islanded microgrid operation.[16] One example of managing DERs in a manner that improves the overall performance of the electric distribution system is the microgrid. Microgrids are small-scale distribution systems that link and coordinate multiple DERs into a network serving some or all of the energy needs of one or more users located in close proximity. The microgrid control hierarchy includes microgrid controllers, asset management controllers, and DMS.[17]

Microgrids require control systems that are capable of managing loads and the operation of generators as well as determining when and how to transfer between grid-tied and islanded modes. In the islanded mode of operation, the DERs are mainly controlled to regulate the microgrid voltage magnitude and frequency. Consequently, the microgrid controller can specify the commands for steady-state voltage magnitude and frequencies of the DERs to ensure the wellbeing of the loads or safe reconnection of the microgrid once the operating mode is to be switched to grid tied mode.[18]

The smart inverters that link solar PV and battery resources to the grid have advanced message processing and fast power control with nearly instant response to received commands and monitored conditions. Over the last few years, industry efforts have defined a wide range of standard grid-supportive functions that inverters are capable of and standard communication protocols that allow these functions to be remotely managed. These electronic inverter capabilities can transform high penetration DER from problematic uncertainties to beneficial tools for distribution management. To achieve these potential benefits, DMS must account for the presence of DER in its models and advanced applications. Interoperability of systems requires open standards which include both functional behaviors (i.e., standardizing the DER-related use cases and services on the enterprise), and the communication standards (information models), needed to support DER functions.[19]

Advanced inverter functionalities represent an opportunity to improve the stability, reliability, and efficiency of the electric power distribution system, particularly as DER becomes increasingly incorporated onto the grid. Autonomous implementation of advanced functionalities could provide localized

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[15] Ibid.

[16] *Smart Distribution Applications for Distributed Energy Resources.* EPRI, Palo Alto, CA: 2013. 070625.

[17] Ibid.

[18] *Smart Distribution Applications for Distributed Energy Resources.* EPRI, Palo Alto, CA: 2013. 070625.

[19] Ibid.

nodes of stability and control on a distribution feeder.[20] Interconnected advanced inverters could have significant beneficial impact upon the efficiency and reliability of the distribution system when paired with sophisticated communication, augmented protection, and intelligent control. Utility distribution automation or DMS will be central to the integration of these functionalities, enabling necessary and sufficient communication, protection, and control measures. Inverters' power electronic circuit capabilities, if properly exposed and integrated with DMS, can transform high penetration DER from problematic uncertainties to beneficial tools for distribution management.[21]

Work and research involving DER, DMS, and microgrids has been ongoing for years and have been pivotal in developing standards from a grid-connected standpoint. The concepts being addressed with this document include extending the capabilities of established architectures within a microgrid controller and addressing how other architectural components fit in with respect to end to end connectivity. This document essentially explores an established architecture defined and studied in the past, but with the addition of a microgrid controller where there has not yet been one.

2.1 High Level Architecture

This document is discussed based on a "bottom up" architectural perspective that specifically examines DER, defines functions, and addresses various relationships with DERMS. This approach was chosen over a "top down" perspective to further address the role of the microgrid controller and its responsibility with respect to controlling the DERs when the system is in islanded mode. Additionally, this approach allows for further development of existing work to integrate the functions of available resources during grid connected mode. This document defines the linkage of microgrid controllers and how they will interact with DER as well as how it connects with DMS specifically through end to end connectivity between DMS and DER.

Figure 2-1 illustrates the overall utility system architecture. Both the microgrid controller and DERMS interact with the DMS. The figure is broken down into the following segments: Group 1, Group 2, Microgrid Controller 1, Microgrid Controller 2 and Third Parties.

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[20] *Smart Distribution Applications for Distributed Energy Resources: Distribution Management System Use Cases.* EPRI, Palo Alto, CA: 2013. 3002002464.

[21] Ibid.

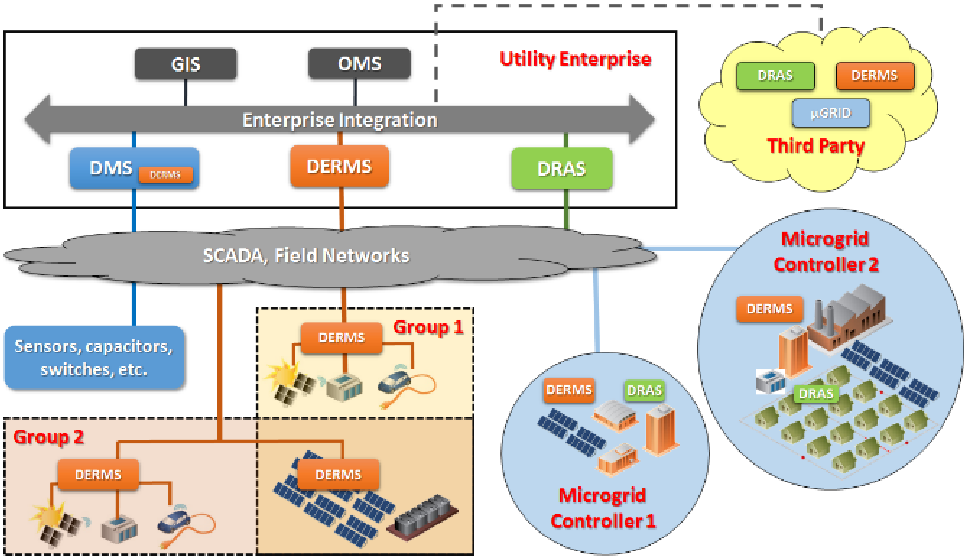

Figure 2-1
Utility High Level Architecture

Group 1 and Group 2: Groups 1 and 2 represent two variations of DER resources which are connected together and controlled by DERMS. Groups 1 and 2 are unrelated to the microgrid in this configuration because the communities represented do not have islanded functionality. Instead the communities use their DERs and participate in the system through DMS connection. There are multiple possible variations of Groups 1 and 2.

Microgrid Controller 1 and Microgrid Controller 2: Microgrid Controllers 1 and 2 are another example of communities where the controlling resources for the communities in grid tied mode include DERMS and DERMS in the microgrid controller. These communities have a local controller called a microgrid controller that also has microgrid function. Islanded functions are integrated if the community is architecturally designed for those to be included. As with Groups 1 and 2, there are multiple possible variations for Microgrid Controllers 1 and 2. Additionally, there can be multiple microgrid controllers associated with each utility.

Third Party: Rather than having local connectivity, all devices are owned by a third party aggregator. For example, in the case of solar, energy storage, etc. a third party aggregator communicates to a vendor and then aggregates the information.

The figure below illustrates the functionality overlap between DERMS and microgrid controllers. Additionally, it provides a clear visual of the two main architectural variations that include DERMS within a microgrid controller as well as the opposite, a microgrid controller within DERMS.

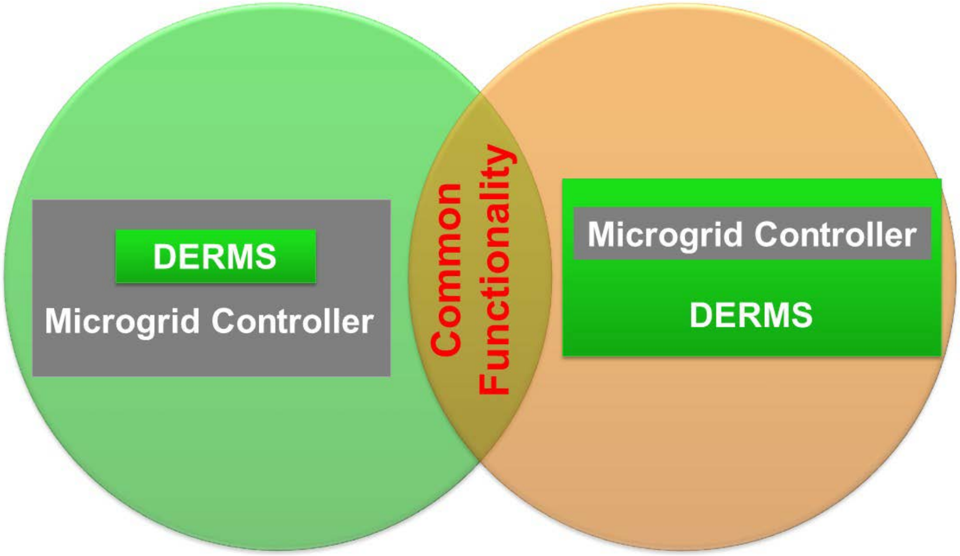

Figure 2-2
DERMS and Microgrid Controller Functionality Overlap

Figure 2-3 below illustrates different variations of Figure 2-1, specifically the relationship variations between DERMS and the microgrid controller. The microgrid controller could be the DER managing entity (DERMS) changing responsibilities and functions when interacting with the DMS. Alternatively, individual DER could be directly communicated to/from a utility system when grid-connected, and switch over to the microgrid controller during islanded operation. The architectures are illustrated by depicting all of the enterprise elements as being attached to the enterprise service bus. This architectural configuration demonstrates that there can be multiple applications involved and the DERMS, DMS, DRAS, etc. are really a set of functions and not necessarily an application or part of an application. Designing the architecture of the system this way provides flexibility.

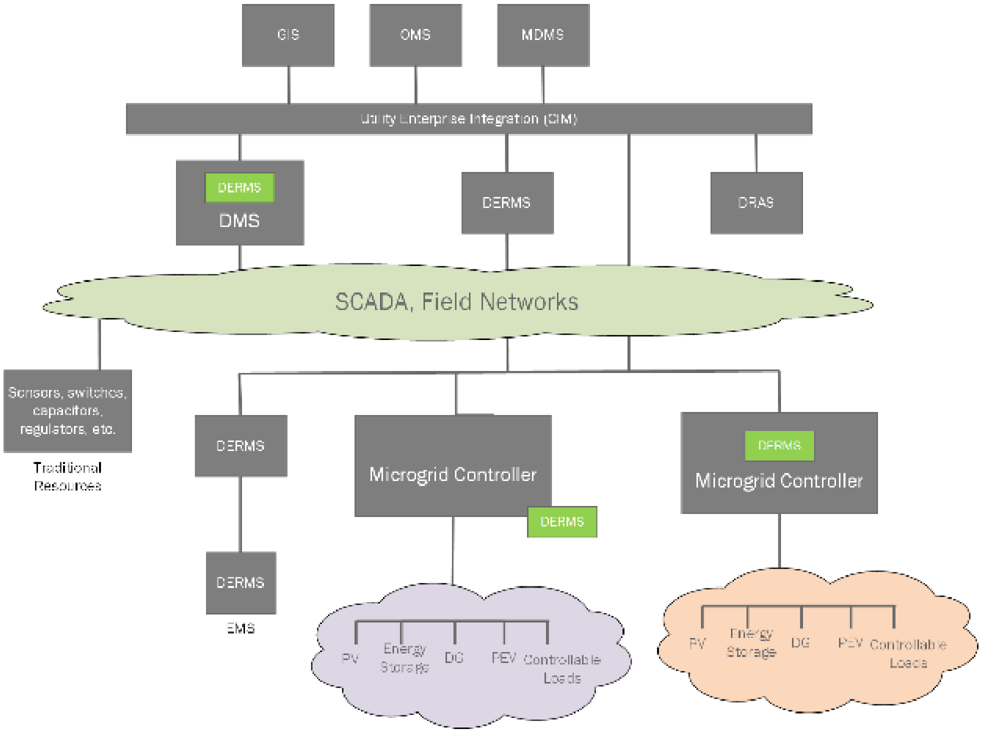

Figure 2-3
Utility High Level Architecture with DERMS Variations

2.1.1 Actor Definitions

The actors defined below are based off of the high level architecture exhibited above in Figure 2-3.

Table 2-1
High Level Architecture Actor Definitions

Actor Name	Actor Definition
Geospatial Information System (GIS)	System used to capture, store, alter, analyze, manage and display information related to spatial or geographical data.
Outage Management System (OMS)	System used by utilities to assist in restoration of power. Functions of OMS include providing outage information regarding the extent and location, prioritizing restoration efforts and resource management.

Table 2-1 (continued)
High Level Architecture Actor Definitions

Actor Name	Actor Definition
Meter Data Management System (MDMS)	This function collects, validates, stores and distributes readings and event-related data from meters and other end devices to other enterprise functions and systems. The meter data management function supports diverse end-use applications including but not limited to billing, load management, load forecasting, demand response, outage management, asset management and distribution network planning and maintenance.[22]
Distribution Management System (DMS)	A software application which monitors and controls the distribution system in conjunction with the operator.[23]
Distributed Energy Resource Management System (DERMS)	This is a particular function for controlling and managing the distributed resources on the distribution system – PV, wind generators, other distributed generation such as fuel cells and gas turbines, energy storage systems, and demand response systems. The DERMS can be considered a part of the overall DMS but is identified separately here for specific discussion and interface with local DER controls and microgrid controllers.
Demand Response Automation Server (DRAS)	System used to accelerate the automation of customer interaction to Demand Response programs and dynamic pricing via a communicating client.
(Microgrid) Supervisory Control And Data Acquisition (SCADA), Field Networks	System which monitors and controls components in the electrical distribution or transmission systems or in other industrial control systems. Typically used to monitor and control remote devices.[24]
Sensors, switches, capacitors, regulators, etc.	Mechanisms that have the capability to detect the loss of power from the area electric power system (AEPS) and disturbances in the AEPS. Switches can open and close automatically and on command from the microgrid controller and can inform the microgrid controller of its status.

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[22] *System Interfaces for Distribution Management Part 1: Interface Architecture and General Recommendations*; 61968 – 1 IEC: 2012

[23] *Use Case 3: Utility Microgrid Controller Monitors Grid System Status and Exerts Control to Ensure Power Delivery for Critical Facilities.* EnerNex: 2015.

[24] *Use Case 3: Utility Microgrid Controller Monitors Grid System Status and Exerts Control to Ensure Power Delivery for Critical Facilities.* EnerNex: 2015.

Table 2-1 (continued)
High Level Architecture Actor Definitions

Actor Name	Actor Definition
Microgrid Controller	A control system that is able to dispatch the microgrid assets, e.g. opening/closing switches, changing control reference points, changing generation/consumption levels, etc.
(Microgrid) Energy Management System (EMS)	The interface to participate in energy market and interact with market operator. It manages the sources and loads in the microgrid, dispatches optimized operational commands to meet economic objectives while the system stability constraints are met.
Photovoltaic (PV)	Methodology that uses semiconducting materials to convert solar energy into direct current electricity.
Energy Storage	The use of devices or systems to store energy for future use.
Distributed Generation (DG)	Energy that is generated and stored in some manner through DER devices and used for future energy needs.
Plug-in Electric Vehicle (PEV)	Motor vehicle that can be charged electrically from an external source.
Controllable loads	Non-essential energy demands that can be managed by meeting requirements by deferring energy with no adverse effects.

2.1.2 Communications Protocols

The table below discusses communications protocols between the actors: these exchanges are bi-directional. The actors are derived from the list of actors from Table 2-1.

Table 2-2
Communications Protocols

Actor 1	Actor 2	Potential Communications Protocols
Microgrid Controller EMS	Market Operator	IEC 61870
Microgrid Controller EMS	Microgrid SCADA	IEC 60870, IEC 61970, IEC 61850
Microgrid SCADA	Area Power System	IEC 61870
Microgrid SCADA	Microgrid switch	IEC 60870, IEC 61970, IEC 61850, DNP3
Microgrid Controller EMS	Microgrid switch	IEC 60870, IEC 61970, IEC 61850, DNP3
Microgrid SCADA	Protection controller	IEC 60870, IEC 61970, IEC 61850, DNP3
Microgrid Controller EMS	BMS	IEC 61850, IEC 61970, IEC 61870
Microgrid Controller EMS	Individual DER	IEC 61850, IEC 61970, IEC 61870, DNP3, SEP2.0 (IEEE 2030.5), SunSpec Alliance, CEA 2045, Vendor-specific APIs, IEEE 2030.7
Microgrid Controller EMS	DMS	IEC 60870, IEC 61970, IEC 61850

Figure 2-4 below illustrates the concept of a virtual top node (VTN) and a virtual end node (VEN). VENs are devices (commercial, industrial, and residential consumer products) that represent the load and consume energy from the power grid.[25] Virtual Top Node (VTN) refers to the logical functionality of a system to do things like manage resources downstream and provide requested responses To trigger a response from a resource in support of a grid situation or optimization, messages describing the situation must be passed along to the resource. The resource will handle the situation based on knowledge of the current state of the device and its components. With the smart grid automation logic architectural configuration, the "how" is no longer left up to the discretion of the VEN and as a result some effort will need to go into determining the information that must

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[25] *Concepts to Enable Advancement of Distributed Energy Resources: White Paper on DER.* EPRI, Palo Alto, CA: 2010. 1020432.

be communicated.[26] In the case of a reliability event, a brief emergency load shed message to the VEN can be utilized. This serves as an example of where the situation meaning is required to enable the decision making at the VEN. In traditional direct load control systems, devices may be deactivated due to reliability, price, peak shifting etc. If the event is a grid reliability event of a brief nature, smart devices that are not a candidate for a load reduction of a longer duration may be willing to contribute temporarily to the solution. This enables huge potential benefits. The device may be performing a function during which, although a delay of several hours may not be feasible or acceptable, a short delay could be considered reasonable and enable the addition of a large amount of reliability resources.[27]

By defining its ability to respond a DER end node becomes an available resource which is controlled by the next higher level entity. The smart grid systems do not need to know any details about the intricacies of a product introduced to the grid with “smart” capabilities. Because of this, an open market of new product design, innovation, and continuous product improvement is enabled. Because of the possibility to logically separate the physical devices/resources from their respective characteristics, the systems view becomes manageable because the utility entity can identify the criteria needed from a DER device or system based on capability rather than tied to physical systems. With the VEN architecture in place the logic driving the priorities can still remain at the utility entity. The resources can still be called on for any of a number of reasons including capacity, reliability, financial, emissions or any other future goal of the system. The business drivers remain in the logic of the utility entity that communicates the grid status and needs down to the end nodes.[28]

Virtual Top Node (VTN) refers to the logical functionality of a system to do things like manage resources downstream and provide requested responses. The VTN is responsible for determining what resources are available and when and why to send specific grid messages to the resources being managed. A VTN can utilize a number of VEN resources to accomplish something based on the current utility needs. All VENs can receive and respond to a message selected from the same message set. A key part of this concept is that the VTN knows what each VEN has to offer in terms of a dynamic response capability definition. The function of a VTN is defined in terms of a DER. Its capabilities can change in real time as it tracks the capabilities its VENs are currently offering. A VTN can also be designed to manage its resources provided by the VENs in such a way that it could be considered as a fixed capacity resource.[29]

In this architectural set up the VEN is only aware of one upstream VTN. Further, a VEN is capable of functioning as a VTN by aggregating additional

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[26] Ibid.

[27] *Concepts to Enable Advancement of Distributed Energy Resources: White Paper on DER.* EPRI, Palo Alto, CA: 2010. 1020432.

[28] Ibid.

[29] Ibid.

resources below it and directing subordinate VENs. A VTN is able to control multiple downstream VENs and does not need knowledge of the VEN, only the VEN capabilities. Essentially a VTN reports upstream what it is capable of providing. A VTN does not control any systems but rather communicates downstream to a VEN or multiple VENs its current capabilities. The VEN is the point where control of any system and hardware takes place, thus a microgrid controller is considered to be a VEN. A VEN is free to utilize any of the resources it can control. These could be hardware components, other devices, or identities that qualify as a VEN in their own right, including a microgrid controller. In the case of Figure 2-3 VENs would include DERMS devices as well as microgrid controllers.[30]

The recursive architecture, which uses one protocol for communication to multiple layers, depicted below enables virtually any business model, load, or resource and facilitates new innovation. In this configuration, devices and systems at the end nodes are equipped to maximize information exchanges between controllers by adjusting energy consumption based on the information exchanged. This architecture enables the smart grid to move forward at a much faster pace than has historically been the case. It also addresses technology obsolesce and enables technology development and innovation because new products and devices are able to be added seamlessly as any device designed to received, unpack, and respond appropriately can meet the requirements of a VEN. In the case of a new device, nothing upstream needs to learn how it works so it can be introduced and immediately participate in the smart grid.

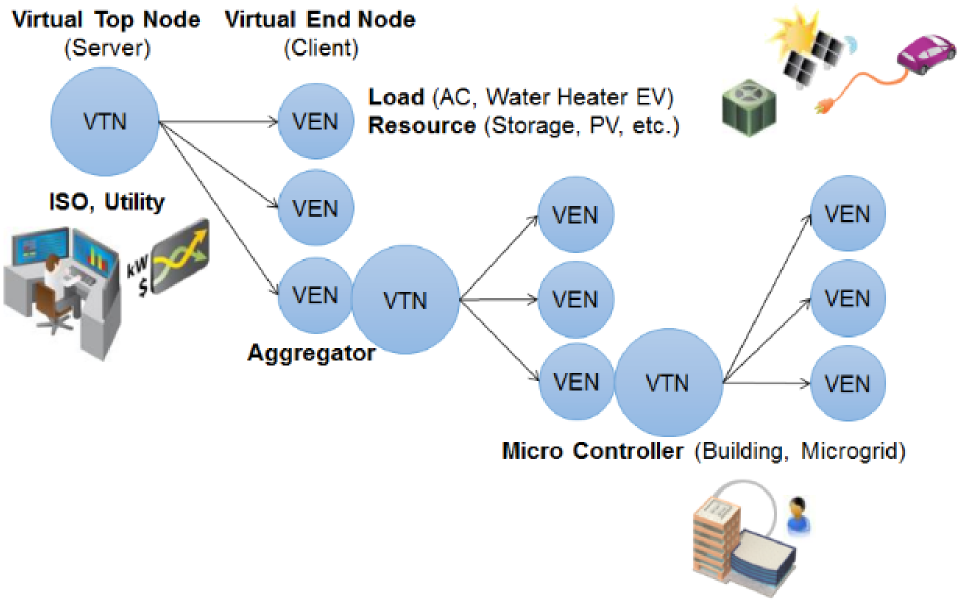

Figure 2-4
Relationship between Microgrids and VTNs and VENs

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[30] Ibid.

This architecture operates with a central resource controller that enables smart devices to be informed and respond independently to higher level grid signals while providing incentives for optimal behavior. This approach is termed “inform and motivate” and works when systems communicate to devices about their status and devices in turn respond appropriately based in the scenario. These “nodes” may reside on different devices with different software loaded or they might be on the same device utilizing one piece of software. A microgrid controller would have a $\mathrm{VTN}_{\mathrm{DR}}$, a $\mathrm{VEN}_{\mathrm{DR}}$, a $\mathrm{VTN}_{\mathrm{DER}}$, and a $\mathrm{VEN}_{\mathrm{DER}}$ along with all its microgrid controlling features. This architecture allows for unlimited flexibility by allowing devices to be replaced as better technology is developed.

2.1.3 Identification of the Microgrid Controller Two Levels

Microgrid controllers are examined at two levels for the purpose of this project. The two levels include interaction between DER and microgrid controller and microgrid controller and DMS. Both the microgrid controller and DERMS interact with the DMS. The microgrid controller could be the DER managing entity (DERMS) changing responsibilities and functions when interacting with the DMS. Alternatively, individual DER could be directly communicated to/from a utility system when grid tied, and switch over to the microgrid controller during islanded operations.

2.1.3.1 DER to Microgrid Controller

When some of the distributed resources on the distribution system are configured into microgrids (with the capability to disconnect and operate in an islanded mode), the resources need a microgrid controller to manage their operation and coordination with local loads.

2.1.3.2 Microgrid Controller to DMS

DMS refers to an integrated set of control functions for management and optimization of distribution system performance both in normal conditions and in abnormal conditions (response to outages, etc.). Specifically, DMS is a tool that assists the distribution system operators in the control center and in the field with performing their duties while not replacing human judgement and decision making. DMS is also used by engineers for engineering analysis and technicians for trouble-shooting and maintenances as well as managers for oversight and decision making support. DMS is used to optimize efficiency, reliability, and system performance.[31]

As customers become more knowledgeable about the electric industry and technology in general, they are demanding the kinds of benefits that come with a sophisticated DMS. These benefits include increased reliability, improved power quality, further integration of renewable energy resources, increased data security

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[31] *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385.

and privacy, and resiliency to natural disasters and other threats with respect to power flow disruption.[32]

DMS is built on a foundation that includes advanced distribution applications that use the information acquired by DSCADA (Distribution SCADA) to improve overall distribution system performance. Advanced applications build on DSCADA monitoring and control capabilities to provide electronic decision-making and automatic control capabilities for system optimization. Advanced distribution system applications that determine control actions needed to optimize distribution system performance would execute such actions via DSCADA. The addition of advanced distribution applications provides a clear distinction between DMS and DSCADA.[33] Advanced distribution applications that pertain to DMS include distribution system modeling, geographical user interface, on-line power flow analysis, switch order management, volt-VAR optimization, optimal network reconfiguration, and predictive fault locations. DMS also interfaces with systems including GIS, OMS, and MDM.

Electric utilities in many jurisdictions are facing Renewable Portfolio Standard mandates to provide significant portions of their load through renewable generating resources. The electric utility must be able to accommodate such new distributed generating resources without adversely impacting the quality of service on the electric distribution system. Accommodating these resources is especially challenging due to the highly variable and intermittent nature of wind and solar powered generating units, which can produce unacceptable voltage and power swings on the feeders. The DMS can include application functions that enable the utility to model the impacts of DERs and develop and execute mitigating operational strategies, such as advanced reactive power control, that can help to minimize the adverse consequences of DERs and thereby accommodate additional DERs on the distribution feeders.[34]

The benefits of a DMS as identified by multiple utilities who recently underwent DMS implementation was outlined in a DMS guide published by the U.S. Department of Energy. Benefits identified include the ability to initiate emergency voltage reductions faster than with in-place SCADA systems, the ability to initiate demand response from DMS, microgrid integration capabilities, the ability to incorporate distributed energy resources and forecasted load into the load model, and modeling capabilities to truly model distributed generation rather than only negative load.[35] With respect to microgrid integration, the microgrid controller manages the connection and disconnection of the microgrid

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[32] *Insights into Advanced Distribution Management Systems.* U.S. Department of Energy: February 2015.

[33] *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385.

[34] *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385.

[35] *Insights into Advanced Distribution Management Systems.* U.S. Department of Energy: February 2015.

from the overall distribution system. Multiple microgrid controllers are able to talk to DMS via different architectural variations.

DMS functions include the following:

- Data acquisition (substation SCADA RTUs, SCADA facilities associated with field devices, AMI meters)
- Data processing (alarm limit checking, reasonability limit checking, data quality processing, normal/off normal processing, alarm detection, sequence of events processing, momentary change direction)
- DMS control outputs
- Geographical User Interface (GUI)
- Intelligent alarm processing
- Historical information systems
- Distribution application functions
- Distribution system model
- Topology processor
- On-line power flow
- Short circuit analysis
- Switch order management
- Volt-VAR optimization
- Fault location, isolation, and service restoration
- Optimal network reconfiguration
- Short term load forecasting
- Dispatcher trainer simulator
- Dynamic equipment rating
- DMS control of protection settings (fuse saving enable/disable, cold load pickup enable/disable)
- DER monitoring and control
- Emergency load shedding
- Integration with eternal systems (GIS, AMI, OMS, EMS, corporate data historian).[36]

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[36] *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385.

An example list of DMS requirements is provided below.[37]

Table 2-3
Sample DMS Requirements

Category	Requirements
Load Flow	• Ability to adjust the current load profile by scaling (%) • Ability to manually override calculated load, calculated voltage, distributed generation values, and • inputs from SCADA or non-SCADA sources • Ability for system to model a load profile for all transformers within the distribution system • Ability of the operational model to always be consistent with the status of the real-time network so that the system uses the correct, current state • Ability to calculate load flows on a periodic basis • Ability to calculate voltage and load flow values along a circuit or branch by using both SCADA and manually entered voltage and/or load information as a reference value at selected points along the circuit or branch • Ability to establish profiles that vary by time of day, day of week, and season of year • Ability to recommend actions for selected portions of the network to optimize power system performance and efficiency using volt/VAR control • Ability to recommend actions for selected portions of the distribution system to optimize power system performance and efficiency using volt/VAR control
Monitoring	• Ability to continuously monitor the power system to predict overloads • Ability to continuously monitor the power system to predict voltage violations
Alarms	• Ability to generate an alarm and highlight out-of-tolerance voltage conditions along the feeder at any point • Ability to generate an alarm and highlight out-of-tolerance loading of transformers, fuses, switches, conductors, and all other feeder equipment • Ability to drill down from the alarm and view detailed power system information related to that alarm

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[37] *Insights into Advanced Distribution Management Systems.* U.S. Department of Energy: February 2015.

Table 2-3 (continued)
Sample DMS Requirements

Category	Requirements
Integration	• Ability to import and apply equipment ratings for substation transformers from an external system at a configured interval no less than daily • Ability to bring in analog and digital information from SCADA as an input for load flow operations • Ability to receive a refresh of the entire power system from the SCADA database after lost connectivity between SCADA and NMS • Ability to bring in a transformer load profile as an input for power flow operations and feeder load management as frequently as daily • Ability to import and display equipment ratings, analog, and digital information for substation equipment from an external system (CBM) on a real-time basis
User Interface	• Ability to display SCADA analog and digital values in near-real time • Ability to display power flows and load and voltage information (analog values and violations) in real time for the device selected from both graphical and schematic views • Ability to receive alarms for substation equipment from an external system (CBM) on a real-time basis • Ability to view power flow results, load, voltage, violations, and available capacity on one or more circuits that have tie capability with each other • Ability to bring in and display Distribution SCADA Limit Alarms (high and low), status changes, and system (lost server)
Reports	• Ability for operators and non-operators to view a list of all cuts, jumpers, and devices not in their normal state
Study Mode	• Ability to select load profile in study mode for suggested switching • Ability to request a mitigation/switch plan to address predicted system overloads and voltage violations • Ability to initialize study mode to the load conditions that match the conditions that generated the alarm

Table 2-3 (continued)
Sample DMS Requirements

Category	Requirements
Load Curtailment	• Ability to generate a switching plan from predefined templates to shed load • Ability to relate outages/events to a single load curtailment event • Ability to restore customers that were shed during load curtailment (upon operator initiation via go backs)
System Forecast	• Ability to provide switching and load transfer data to an external database by date/time range, on 1 or more selected circuits, indicating tie switches opened/closed, load reads on each circuit before and after switching, and duration of transfer • Ability to provide switch device events to an external database to create an abnormal device report by date/time range

The table below documents the conditions of the microgrid controller and DMS during normal and fault conditions and specifically notes the relationship between the interfacing systems. This table provides specific emphasis on the information communicated between the two systems and which systems is responsible for said communication.

Table 2-4
Communication & Function Mapping between Microgrid Controller and DMS[38]

Microgrid Controller	DMS	Communicating System
Normal Conditions		
Real-time data at the PCC (voltage, current, active/reactive power)	Real-time data at the PCC (voltage, current, active/reactive power)	Both with each other
Basic internal microgrid to designate potential wheeling paths	Be cognizant of possible wheeling paths in the microgrid	Microgrid controller to DMS
Fault Conditions		
Emergency support to the distribution grid if necessary	Emergency support to the microgrid if necessary	Both with each other

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[38] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

Table 2-4 (continued)
Communication & Function Mapping between Microgrid Controller and DMS

Microgrid Controller	DMS	Communicating System
Disconnection under severe fault condition in the distribution grid if it is not cleared by the distribution grid protection within the allotted period of time of the microgrid reaction to a distribution grid fault	Severe fault is either not detected or not cleared by the distribution grid protection within the allotted period of time of the microgrid reaction to a microgrid fault	DMS to microgrid controller
Severe fault is either not detected or not cleared by the microgrid protection within the allotted period of time of the distribution grid reaction to a microgrid fault	Disconnection under sever fault condition in the microgrid if it is not cleared by the microgrid within the allotted period of time of the distribution grid reaction to a distribution grid fault	Microgrid controller to DMS
During unintentional islanding load balancing and voltage profile recovery is prioritized	During unintentional islanding load shedding and/or local DER generation is increased while VVO re-optimizes the voltage profile	Both with each other
During intentional islanding, notify the DMS to prepare for disconnection while balancing the active and reactive demand in the microgrid	During intentional islanding, prepare for disconnection when received the request from the microgrid while balancing the active and reactive demand in the distribution grid	Both with each other
Reconnection notification to the DMS	Prepare for the microgrid reconnection and begin normal operations once the reconnection is terminated	Microgrid controller to DMS

DMS uses available DERs, both customer owned and utility company owned, to help control real and reactive power requirements on the distribution system. A DMS can request distributed generation power factor modifications and remote generation disconnection. It also monitors in real-time, actions taken by the Independent Power Producers (IPP), such as verification that requested load reduction has actually taken place, and is able to use a customer's distributed generation unit to help control real or reactive power imbalance on a distribution circuit. A DMS is useful with respect to DER because it enables the utility to monitor the performance of customer owned power generators. DMS includes facilities to enable the utility to incorporate IPPs into real-time generation dispatch and control. The DMS monitors energy flow at the metering point to determine customer response. DMS also includes monitoring and control of islanded portions of the distribution system powered by microgrid controllers. However, as it stands with respect to DMS, there are existing gaps with functionality and integration that link DMS to microgrid controllers.

2.1.4 Relationship and Roles Between DERMS and Microgrid Controllers during Grid-Tied and Islanded Modes

DERMS is the managing entity for distributed resources on the distribution system which controls and manages resources like PV, wind generators and other distributed generation such as fuel cells and gas turbines, energy storage systems, and demand response systems. Microgrid controllers are responsible for managing the operation of microgrids – generation and loads – as well as coordinating connection and disconnection of the microgrid from the overall distribution system. During grid-tied mode the microgrid controller is a passive system; however, when the microgrid is in islanded mode the microgrid controller coordinates energy distribution from the DERMs.

2.2 Architecture Variations

2.2.1 One Local Microgrid Controller Interfaces to the System Controller

2.2.1.1 Multiple DERMS Outside of DMS Interacting

The figure below illustrates multiple variations of DERMS connected to the enterprise bus and interacting with DMS, which is also connected directly to the enterprise bus. The purpose of the figure is to illustrate multiple DERMS interacting with DMS.

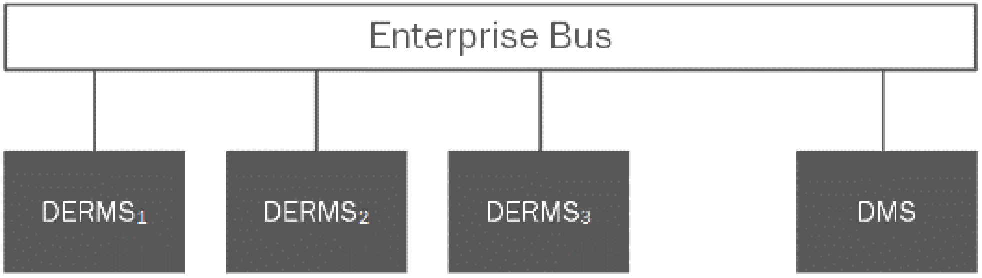

Figure 2-5
Local Microgrid Controller Interfacing to the System with Multiple DERMS Outside Interacting Together

2.2.1.2 DERMS Within DMS

The figure below illustrates one microgrid controller interfacing with the system controller with the DERMS contained within DMS. This figure also illustrates that microgrid controllers are able to have their own DERMS that area completely independent.

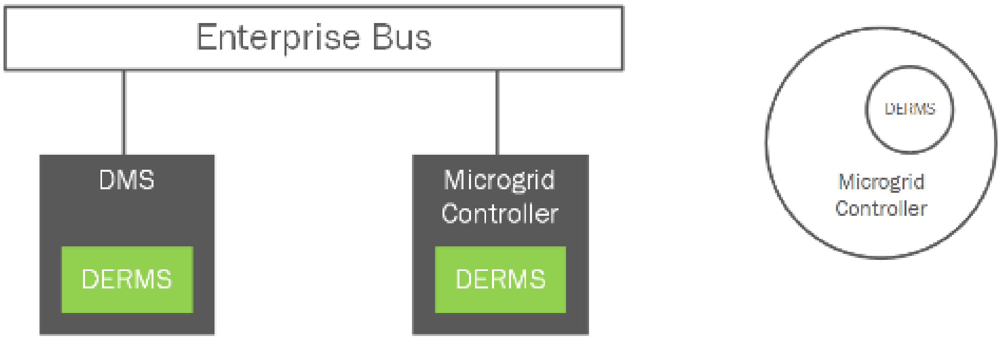

Figure 2-6
Local Microgrid Controller Interfaces to the System with DERMS Within DMS

2.2.2 Multiple DERMS Interfacing with One Microgrid Controller

The figure below illustrates multiple DERMS interfacing with one microgrid controller. There is also a firewall present and one of the DERMS is communicating through the firewall. The DERMS are all connected directly to the enterprise bus as are the DMS and microgrid controller. The box that depicts the microgrid controller is intended to represent its domain which includes multiple DERMS within one microgrid controller.

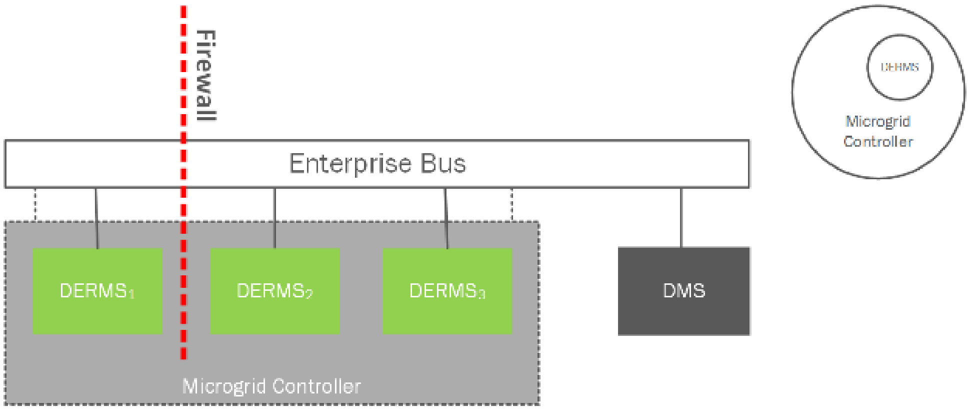

Figure 2-7
Multiple DERMS Interfacing with One Microgrid Controller

2.2.3 Local Microgrid Controller Housing the Local DERMS

2.2.3.1 Multiple Microgrid Controllers Interfacing with DER through DERMS

The figure below illustrates an architectural variation in which a local microgrid controller is housing the local DERMS and multiple microgrid controllers are interfacing with the DER through DERMS. The figure depicts local microgrid controllers that can house one local DERMS or multiple DERMS all of which are connected to the enterprise bus along with DMS.

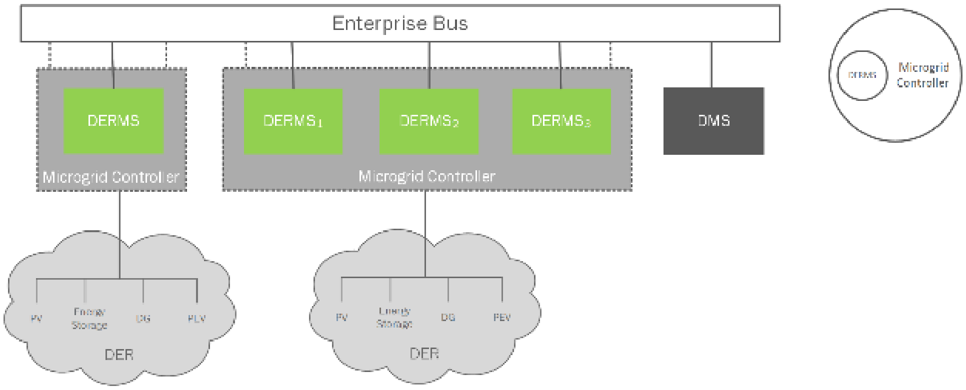

Figure 2-8
Multiple Microgrid Controllers Interfacing with DER through DERMS

2.2.3.2 Multiple Microgrid Controllers Talking to DER Directly

The figure below is similar to the figure above; however, the microgrid controllers are talking to DER directly rather than through DERMS. The microgrid controllers are controlling their respective DERs and are capable of communicating with each other through the enterprise bus and sharing DER assets. Additionally the dotted line between the microgrid controllers indicates that they are able to communicate and cascade capabilities.

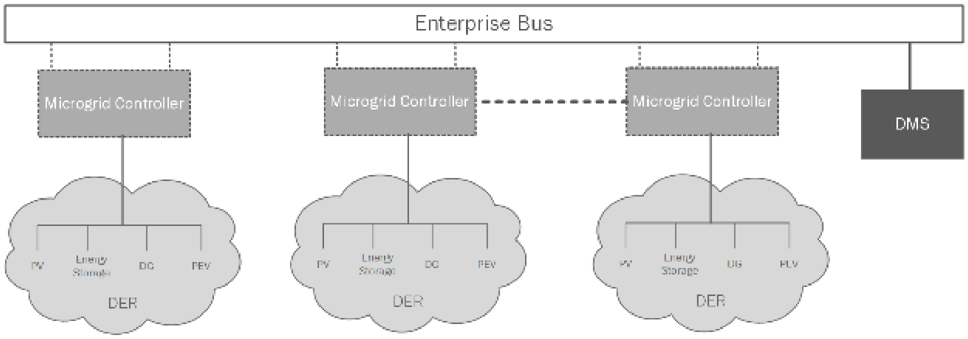

Figure 2-9
Multiple Microgrid Controllers Talking to DER Directly

Section 3: DER To Microgrid Controller/DERMS

The purpose of this section is to map controller architecture with DERs, identifying functions, requirements, information models and messages. There are two main architectures for microgrid controllers which are DER to the microgrid controller/DERMS and the microgrid controller/DERMS to DMS. This section discusses DER to the microgrid controller/DERMS. Functions are considered to be the purpose for what the microgrid controller was intended. Requirements are a step below functionality as they are the components necessary to allow the functions to operate properly.

3.1 Layered Microgrid Architecture (From DERs to Microgrid Controller/ DERMS)

The "*general purpose*" layered microgrid architecture from DERs to grid interaction is shown in Figure 3-1.

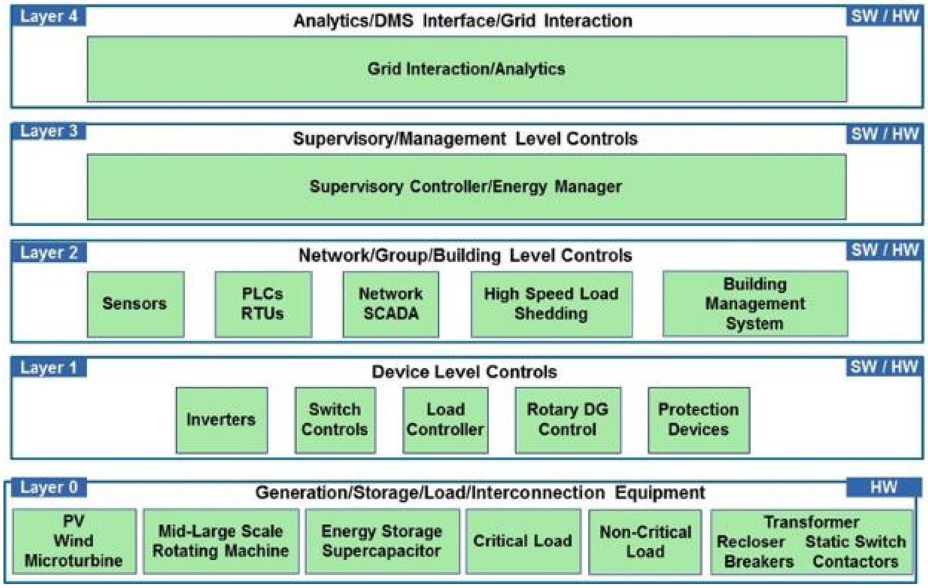

Figure 3-1
Layered Microgrid Architecture from DERS to Grid Interaction
[Source: EPRI, LBNL, Microgrid Labs]

The "*general purpose*" microgrid controller architecture is based upon a multi-layered strategy for managing and controlling the distributed resources and loads that may be part of local microgrids. The specific layers identified here include device level control, network level control, supervisory control, and grid interactions/analytics, which are further discussed below.

- **Layer 0** captures the DER types and load types and pertains to energy generation (resources) and storage as well as load requirements.
- **Layer 1 (**device level control**)** includes the individual device level control.
- **Layer 2** (network level control) is the control layer which manages DER, including scheduling and dispatching and their network connectivity and where operational commands are sent out.
- **Layer 3** (supervisory control) consists of supervisory control where energy management activities are performed
- **Layer 4** (grid interactions/analytics) provides the grid connectivity to DMS, SCADA, and market.

3.1.1 Device Level Control

Device level control entails interacting with the local DER itself to perform certain functions including: device switching (physical isolation, on/off, fault clearing), device protection (fault sensing, fault controls, re-synchronization), inverters/variable frequency drives (VFDs) (power conversion, power control, voltage and frequency control), primary frequency control (inverter droops, governor droops), and other controls (master voltage and frequency, island detection, re-synchronization). Device level control receives and transmits signals through the network control layer. Most device level control is done using device-specific proprietary messaging, which makes the implementation of a microgrid costly, time consuming and complex.

3.1.2 Network Level Control

Network level control ties together all of the multiple device level controls that are distributed and allows for data exchange, sequencing and coordination of all of the individual devices. It includes both logic and a human machine interface.

3.1.3 Supervisory Level Control

The Supervisory Level control layer is the control and coordination layer for DERs to microgrid controller/DERMS.

3.1.4 Grid Interaction and Analytics

The Grid Interaction and Analytic layer includes advanced algorithms performing the optimization for interactions and communication between DERs and the microgrid controller/DERMS.

3.1.5 Actor Definitions for DER to Microgrid Controller/DERMS

The actors listed below are based on the architecture from Figure 3-1. Layer 0 is a critical layer and pertains to energy generation (resources) and storage as well as load requirements.

Table 3-1
Layer 0 Actor Definitions

Layer 0: Generation/Storage/Load	
PV, Wind, Microturbine	Energy generation sources
Mid-Large Scale Rotating Machine	Energy generation source
Batteries and Energy Storage Supercapacitor	Batteries and energy storage device that is capable of storing exponentially more energy than electrolytic capacitors and delivering and accepting charge much faster than batteries. Generally used when rapid charge and discharge cycles are required.
Critical Load	Loads within the microgrid having the highest priority of service. These loads will be served at the expense of all other loads in the microgrid and at the expense of any other service the microgrid could provide. The priority of loads within the critical loads is not distinguished.[39] Examples include hospitals, emergency lighting, other emergency services, and entities deemed necessary.
Non-Critical Load	Loads within the microgrid having the lowest priority of service. These loads may be left unserved in favor of critical loads. The priority of loads within the critical loads is not distinguished.[40]

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[39] *Microgrid Functional Use Case #F-1, Frequency Control.* ORNL: 2014. ORNL_UC_F-1.doc

[40] Ibid.

Table 3-2
Layer 1 Actor Definitions

Layer 1: Device level controls	
Breakers, Contactors, and Switches/Automated Switchgear	Electric switches used to control, protect, and isolate electric circuits; switches that can break an electrical circuit without human intervention and divert the current from one line to another.
Inverters	Electronic device that converts DC to AC electrical power
Static Switch	Provides an automatic transfer of load from the preferred to a backup or alternate energy source.
Load Controller	Mechanism to monitor and control power usage and conducts load shedding during peak energy demands periods.
Rotary Distributed Generation Control	Control scheme specific to a distributed generation unit that is based on some form of rotating machine.
Protection Devices	Devices used for protection of electrical power systems from faults.

Table 3-3
Layer 2 Actor Definitions

Layer 2: Network/Group/Building level controls	
Sensors	Mechanism used to detect energy status information
(Programmable Logic Controller) PLCs (Remote Terminal Units) RTUs	Device that interfaces objects in the physical world to a distributed control system.
Network SCADA	Communications system for the SCADA data
High-Speed Load Shedding	Interrupting energy supply to accommodate demands that exceeds available energy resources.
Building Management System/Building Automation System	A traditional integrated facility-wide building management control system for monitoring and control of temperature and HVAC set points, operation of facility equipment (boilers, chillers, pumps, hot water, chilled water, cooling towers, economizers, etc.)

Table 3-4
Layer 3 Actor Definitions

Layer 3: Supervisory/Management Level Controls	
Supervisory Controller/Energy Manager	Person responsible for overall operation of facility energy resources.

Table 3-5
Layer 4 Actor Definitions

Layer 4: Analytics/DMS Interface/Grid Interaction	
Grid Interaction/Analytics	Analysis of information gathered from energy usage and requirements.

Figure 3-2 captures the architecture variations that different microgrid controller vendors can have at different microgrid system deployments in terms of controls, operations, capabilities and connectivities.

Figure 3-2
Architectural Variations of Different Microgrid Controller Capabilities

3.2 Process Approach

Figure 3-3 below is a flowchart of the process further detailed in Section 3.3 through Section 3.5. The process was initiated by collecting use cases that were relevant to the objectives of the project. Available use cases were compiled and the functions defined in each use case was listed. Once the functions were determined, the use case requirements were mapped to each function and then the data exchanged was identified. Finally messages were mapped to the data exchanged. In the case that a message was not available it was noted and recommended that messages are defined for the gaps in the future. It should be noted that the process was the same for both grid tied and islanded mode.

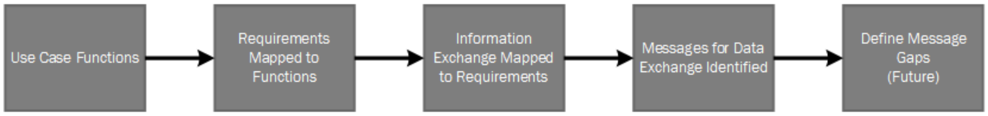

Figure 3-3
Process Flow Chart

3.3 Microgrid Use Cases

The table below lists all of the use cases that were referenced in this document for the purpose of compiling a complete list of microgrid controller functions and requirements.

Table 3-6
Use Cases Referenced

Use Case Title	Use Case Abbreviation	Function
Microgrid Functional Use Case #F-1 Frequency Control	ORNL1	Voltage and Frequency Control (Islanded)
Microgrid Functional Use Case #F-2 Voltage Control (Grid- connected and Islanding)	ORNL2	Voltage and Frequency Control (Islanded) Voltage Regulation (Islanded)
Microgrid Functional Use Case #F-3 Grid Connected to Islanding Transition – Intentional	ORNL3	Grid-Connected to Islanding Transition (Intentional and Unintentional) (Islanded)
Microgrid Functional Use Case #F-4 Unintentional Islanding to Grid-Connected Transition	ORNL4	Islanding to Grid-Connected Transition (Islanded)
Microgrid Functional Use Case #F-5 Islanding to Grid-Connected Transition	ORNL5	Islanding to Grid-Connected Transition (Islanded)
Microgrid Functional Use Case #F-6 Energy Management (Grid-Connected and Islanding)	ORNL6	Economic Dispatch (Islanded)
Microgrid Functional Use Case #F-7 Microgrid Protection	ORNL7	Protection (Islanded)
Microgrid Functional Use Case #F-8 Ancillary Services (Grid-Connected)	ORNL8	Economic Dispatch (Islanded)
Microgrid Functional Use Case #F-9 Microgrid Protection	ORNL9	Black Start (Islanded)
Microgrid Functional Use Case #F-10 Microgrid User Interface and Data Management	ORNL10	User Interface and Data Management (Islanded)

Table 3-6 (continued)
Use Cases Referenced

Use Case Title	Use Case Abbreviation	Function
Requirements for Distributed Energy Resource Management Systems	DER Management Systems	Power Curtailment (Grid Tied) Volt-VAR Management and Power Factor (Grid Tied) Voltage and Frequency Ride-Through (Grid Tied) State/Status Monitoring (Grid Tied) Event Logging (Grid Tied) Multiple Grid Configurations/ Operations (Islanded)
Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1	Test Plan for DER	Storage Management (Grid Tied) State/Status Monitoring (Grid Tied) Dynamic Reactive Current (Islanded)
Enterprise Integration Functions for Distribute Energy Resources	Functions for DER	Connect/Disconnect – Non-Islanding (Grid Tied) Voltage and Frequency Ride-Through (Grid Tied) Voltage Regulation (Islanded)
Use Case 1: Facility Microgrid Reduces Outage Duration Following Natural Disaster Campus	EPRI/EnerNex1	Power Quality and Reliability (Islanded)
Use Case 2: Facility Microgrid Reduces Outage Duration Following Natural Disaster Facility	EPRI/EnerNex2	Power Quality and Reliability (Islanded)
Use Case 3: Utility Microgrid Controller Monitors Grid System Status and Exerts Control to Ensure Power Delivery for Critical Facilities	EPRI/EnerNex3	Power Quality and Reliability (Islanded)
Use Case 4: Utility Bills for Microgrid Services	EPRI/EnerNex4	Additions to State/Status Monitoring (Islanded)
Use Case 5: Utility Tests Community Microgrid	EPRI/EnerNex5	Additions to State/Status Monitoring (Islanded)
Microgrid Interactive Use Cases #IA-1: Information Support for Coordination of EPS and Microgrid Load Shedding Scheme	NIST1	Load Shedding (Islanded)

Table 3-6 (continued)
Use Cases Referenced

Use Case Title	Use Case Abbreviation	Function
Microgrid Interactive Use Cases #IA-2: Coordination of Volt/VAR Control in Connected Mode Under Normal Operating Conditions	NIST2	Volt-VAR Management and Power Factor (Grid-Tied) Voltage and Frequency Ride-Through (Grid-Tied)
Microgrid Interactive Use Cases #IA-3: Update Aggregated at PCC Real and Reactive Load-to-Voltage Dependencies Under Normal Operating Conditions	NIST3	Aggregated real and reactive load-to-voltage dependencies at PCC under grid tied mode
Microgrid Interactive Use Cases #IA-4: Updates of Capability Curves of the Microgrid's Reactive Power Sources	NIST4	Power Quality and Reliability (Islanded)
Microgrid Interactive Use Cases #IA-5: Updating Information on Microgrid Dispatchable Load	NIST5	Economic Dispatch (Islanded)
Microgrid Interactive Use Cases #IA-6: Updates of the Information on Overlaps of Different Load Management Means Within Microgrids	NIST6	Load and Generation Following (Islanded)
Microgrid Interactive Use Cases #IA-7: Updating Dependencies of the Microgrid Operational Model on External Conditions	NIST7	Additions to State/Status Monitoring (Islanded)
Microgrid Interactive Use Cases #IA-8: Update Aggregated at PCC Real and Reactive Load-to-Frequency and Load-to-Voltage Dependencies in the Emergency Ranges	NIST8	Voltage and Frequency Control (Islanded)
NEDO System Use Case #H1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of Biomass and Mitigates Negative Effects of Intermittent Generators on Distribution Grid	NEDO H1	Storage Management (Grid Tied)

Table 3-6 (continued)
Use Cases Referenced

Use Case Title	Use Case Abbreviation	Function
NEDO Systems Use Case #H2: Energy Management of Microgrid Under Islanding Operation that Makes Optimum Use of Biomass and Maintains Power Quality	NEDO H2	Economic Dispatch (Islanded)
NEDO System Use Case #A1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of City Gas as the Fuel and Mitigates Negative Effects of Intermittent Generators on Distribution Grid	NEDO A1	Economic Dispatch (Islanded)
NEDO Local Level Use Case #A2: Autonomous Decentralized Control of Microgrid Which Consists Only of Generating Equipment with Grid-Connected Inverters, Under the Islanding Operation	NEDO A2	Load and Generation Following (Islanded)
Sendai Use Case: Microgrid to Supply Power at Multiple Power Quality Levels (NEDO Sendai Project)	NEDO Sendai	Power Quality and Reliability (Islanded)
NEDO System Use Case #K1: Energy Management by Configuring a Virtual Microgrid Using Public Communications Where Power is Supplied to End-Users While Achieving Simultaneous Balancing of Supply and Demand	NEDO K1	Economic Dispatch (Islanded)

Sections 3.3 through 3.6 discuss microgrid controller functions, requirements, data exchanged and available messages. The information was gathered from the uses cases identified in the table above and then organized into tables. Various functions for microgrid controllers were identified and then matched with a related use case. Microgrid controller functions are identified below.

The following table is a list of actors discussed in the following Sections 3.3, 3.4, and 3.5 that were not addressed previously in the report.

Table 3-7
Additional Actors

Actor Name	Actor Description
Area Electric Power System (AEPS)	The electrical power system that normally supplies the microgrid through their point of common coupling.
Area Natural Gas Supply (ANGS)	The natural gas pipeline system that supplies natural gas to the microgrid.
Asset Switches (ASw)	The ASw has the capability to disconnect assets within the microgrid (e.g. NCL) from the microgrid for control purposes. The ASw can receive control signals from the microgrid controller and can inform the microgrid controller of its status.
Centralized Protection Controller (CPC)	This is a central control that is able to communicate with protective devices. It can operate to update settings, or coordinate the operation of protection in real time. This can be a standalone function, or it could be a part of the MCC.
Flexible Load	Controllable load to simulate Critical customer loads; both shedable and non-schedable components.
Market Operator	The market operator accepts bids from assets, such as a microgrid, in its AEPS and dispatches these assets to provide energy and ancillary services to ensure reliability for the AEPS. The market operator may be part of the AEPS or may be a separate entity.
Meter	Measuring device for Microgrid electrical measurements.

Table 3-7 (continued)
Additional Actors

Actor Name	Actor Description
(Microgrid) Control Commands	The control commands sent from microgrid SCADA to individual microgrid actors. The commands dispatch the economic dispatch from the microgrid EMS and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point.[41]
Microgrid Optimizer	Application which optimizes the resources included in the microgrid. Optimization is done using a constrained dynamic dispatch.
Microgrid Load Forecast	Microgrid forecasting includes load forecasting and forecasting of power (available capability) from renewable resources. Forecast weather in short term: temperature, humidity, illumination.
Other Resource	All energy resources in the microgrid except for the primary resources. Other resources could be a generator, energy storage system, or a load.
Point of Common Coupling (PCC)	Point of Common Coupling (PCC)
PMU	Highly accurate measuring device for Microgrid electrical measure, time tags, and frequency synchronization.
Primary Resource	Device
Protection Device (with communications)	Device

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[41] *Microgrid Functional Use Case #F-1, Frequency Control.* ORNL: 2014. ORNL_UC_F-1.doc

Table 3-7 (continued)
Additional Actors

Actor Name	Actor Description
Protection device (without communications)	Device
Protection relay	Device
Recloser	PCC to the grid. Application which optimizes the resources included in the microgrid. Optimization is done using a constrained dynamic dispatch.
Switching device (with communications)	Device
Switching device (without communications)	Device

3.4 Standard Microgrid Functions for Integration

The "*basic*" microgrid functions during grid tied and islanded mode are included in Table 3-8. Figure 3-4 maps each of the functionalities to the different layers within the overall microgrid architecture.

Table 3-8
Standard Microgrid Functions for Integration

Grid-Tied Functions	Islanded Functions
Grid Services • Connect/Disconnect (non-islanding) • Utility SCADA and DMS coordination • Connectivity and interface with power flow models, utility DMS and DERMS • Market interface for capacity, energy, and ancillary services	**Microgrid Services** • Disconnection – Intentional, planned (scheduled, command) – Intentional, unplanned (unscheduled) – Unintentional, unplanned • Resynchronization – Voltage and frequency control • Grid Configurations/Operations • Isochronous/Droop Operations • Protection • Black start • DER anti-islanding (within microgrids) • Market interface for capacity, energy, and ancillary services

Table 3-8 (continued)
Standard Microgrid Functions for Integration

Grid-Tied Functions	Islanded Functions
Local Services (Optimization) • Load and weather forecasting • Energy management and dispatch – Max generation level control – Power quality (PQ), outage, fault detection – Voltage regulation ▪ Volt-VAR management and PF control ▪ Power (Volt/Watt or Freq/Watt) curtailment/control ▪ Power smoothing – DG, storage, load management – Voltage and frequency ride-through	**Local Services (Optimization)** • Load and weather forecasting • Energy management and dispatch – Max generation level control – Load and generation following – PQ and reliability – Voltage regulation ▪ Volt-VAR management and PF control ▪ Power (Volt/Watt or Freq/Watt) curtailment/control ▪ Power smoothing – DG, storage, load management
Operator Services • State/Status monitoring • Communication with DSO/ISO/RTO • User interface and data management • Billing • Event logging	**Operator Services** • State/Status monitoring • Communication with DSO/ISO/RTO • User interface and data management • Billing • Event logging

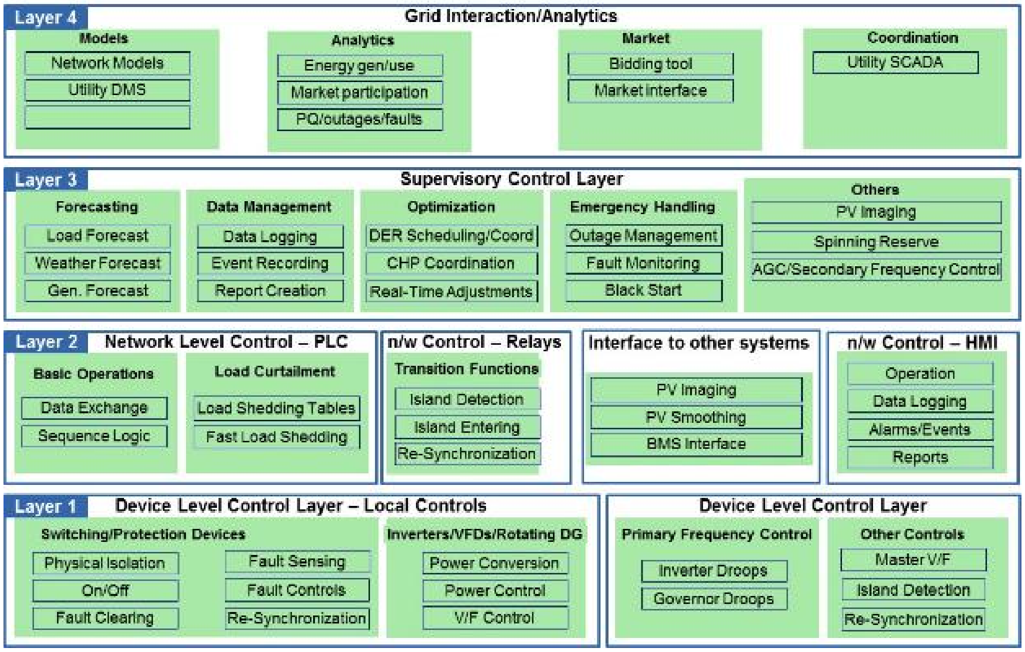

Figure 3-4
DER to Microgrid Controller Functionality [Source: EPRI, LBNL, Microgrid Labs, Spirae]

Sections 3.4.1 and 3.4.2 address microgrid functions for both grid tied and islanded modes by mapping a corresponding use cases or scenario that pertains specifically to each function.

3.4.1 Grid Tied Functions

In this section discusses the functions for a microgrid controller in grid tied mode with a bulleted list of the use case(s) that were used to determine the function and then a short description of the function derived from the use case(s) used.

Connect/Disconnect – Non-Islanding:

- ***Enterprise Integration Functions for Distribute Energy Resources:***
  On/Off Control

  This function allows for remotely turning groups of systems on or off. Potential uses include maintenance, disabling of malfunctioning equipment, and anti-islanding.[42]

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[42] *Enterprise Integration Functions for Distributed Energy Resources: Phase 1.* EPRI, Palo Alto, CA: 2013. 3002001249.

Power Curtailment:

- ***Requirements for Distributed Energy Resource Management Systems:*** *Frequency-Watt Management*

  The frequency-watt function provides a means for limiting the max power delivered or received by a DER. The DERMS must support frequency-watt management. This function can operate in coordination with the reactive power functions and may be particularly useful for helping to avoid extreme frequency events.[43]

Storage Management:

- ***Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1***
- ***NEDO System Use Case #H1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of Biomass and Mitigates Negative Effects of Intermittent Generators on Distribution Grid***

  This function allows a software entity to define a logical group of DER and to exchange the definition of this group (farm) with other applications. The purpose of grouping is subsequent monitoring and management at the group (farm) level.[44] Additionally, this function examines energy management of a grid-connected microgrid system that optimizes the use of biomass (digestion gas, wood biomass) while optimizing renewable energy and mitigates the negative effects on distribution grid (with respect to demand-supply balance and power quality). The microgrid system is connected to distribution grid at a single point and is controlled by the EMS which maintains the amount of power purchased from the distribution grid to contribute to frequency control of the distribution grid and develops an optimum generation schedule in accordance with the load within the microgrid.[45]

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[43] *Requirements for Distributed Energy Resource Management Systems: An Assessment for Taiwan Power Company.* EPRI, Palo Alto, CA: 2013. *3002004363.*

[44] *Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1.* EPRI, Palo Alto, CA: 2014. 3002004681.

[45] *NEDO System Use Case #H1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of Biomass and Mitigates Negative Effects of Intermittent Generators on Distribution Grid.* 2012.

Volt/VAR Management and Power Factor:

- ***Requirements for Distributed Energy Resource Management Systems:*** *Volt-VAR Management*
- ***Requirements for Distributed Energy Resource Management Systems***
- ***Microgrid Interactive Use Cases #IA-2: Coordination of Volt/VAR Control in Connected Mode Under Normal Operating Conditions***

DERMS must support the management of the volt/VAR function. This function enables DER to provide VAR support (leading and/or lagging) in response to the voltage at the local point of common coupling. The standard method for configuring the volt/VAR function is through an array of (V, Q) points which create a piece-wise linear curve. This curve becomes the reference for the inverter to determine what level of reactive power to produce for any given local voltage condition.[46] The DERMS must be capable of managing the power factor of DER. This function is a mutually-exclusive alternative to volt/VAR control and may provide better results on certain feeders under certain circumstances.[47] The third use cases focuses specifically on periodic and event-driven information exchanges between the DMS and the EMS about volt/VAR related parameters.[48]

Voltage and Frequency Ride-Through:

- ***Requirements for Distributed Energy Resource Management Systems:*** *Low/High Voltage Ride Through*
- ***Requirements for Distributed Energy Resource Management Systems:*** *Low/High Frequency Ride Through*
- ***Enterprise Integration Functions for Distribute Energy Resources:*** *Ride Through Service*
- ***Microgrid Interactive Use Cases #IA-2: Update Aggregated at PCC Real and Reactive Load-to-Voltage Dependencies Under Normal Operating Conditions***

L/HVRT refers to the settings for inverters that define their behavior in the presence of short-term over-voltage swells and under-voltage sags. L/HVRT behavior is a function that might be set once and never changed over the life of an inverter. For example, the specific settings may be established by a grid code, configured during the manufacturing process, and never adjusted thereafter. However, it is recommended that these settings be adjustable in inverters, and reconfigurable by DERMS, so that adjustments are supported

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[46] *Requirements for Distributed Energy Resource Management Systems: An Assessment for Taiwan Power Company.* EPRI, Palo Alto, CA: 2013. *3002004363.*

[47] *Requirements for Distributed Energy Resource Management Systems: An Assessment for Taiwan Power Company.* EPRI, Palo Alto, CA: 2013. *3002004363.*

[48] *Microgrid Interactive Use Cases #IA-2: Coordination of Volt/VAR Control in Connected Mode Under Normal Operating Conditions.* Smart Grid Operations Consulting on behalf of National Institute of Standards and Technology: 2015.

if they become necessary.[49] L/HFRT is similar to L/HVRT except that the monitored parameter is system frequency rather than voltage. The IEC standard functions for frequency ride-through are managed in the same way as voltage ride-through, using arrays of (x, y) points to define a piece-wise linear curve. It is also necessary that DERMS have the capability to manage L/HFRT settings for the same reasons given in the previous section. L/HFRT might not need changing, but industry experience has taught that needs may change as distributed generation (DG) levels rise and adjustments may be necessary.[50] Ride through service would allow event ride-through characteristics to be changed across groups of DER to gain manageable/adjustable ride-through services.[51]

The fourth use case listed specifically addresses the function to perform periodic and event-driven information exchanges between the DMS and microgrid operator/microgrid EMS about the aggregated at the microgrid PCC real and reactive load and generation dependencies on voltage within the PCC voltage ranges under normal operating conditions and provides the DMS with relevant data for post-factum analysis when necessary.[52]

State/Status Monitoring:

- ***Requirements for Distributed Energy Resource Management Systems:***
  Inverter Status Monitoring
- ***Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1:***
  Status Monitoring of DER Groups

The DERMS shall be capable of reading status information from inverters in the field. The IEC standard model and DNP3 protocol mapping include support for a wide range of inverter status parameters, all of which should be readable by a DERMS.[53] This function allows the exchange of real-time status information for DER groups. This is dynamic data, including present set/generation value and present max/min dispatchable ranges. [54]

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[49] *Requirements for Distributed Energy Resource Management Systems: An Assessment for Taiwan Power Company.* EPRI, Palo Alto, CA: 2013. *3002004363.*

[50] *Requirements for Distributed Energy Resource Management Systems: An Assessment for Taiwan Power Company.* EPRI, Palo Alto, CA: 2013. *3002004363.*

[51] *Enterprise Integration Functions for Distributed Energy Resources: Phase 1.* EPRI, Palo Alto, CA: 2013. 3002001249.

[52] *Microgrid Interactive Use Cases #IA-3: Update Aggregated at PCC Real and Reactive Load-to-Voltage Dependencies Under Normal Operating Conditions.* Smart Grid Operations Consulting on behalf of National Institute of Standards and Technology: 2015.

[53] *Requirements for Distributed Energy Resource Management Systems: An Assessment for Taiwan Power Company.* EPRI, Palo Alto, CA: 2013. 3002004363.

[54] *Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1.* EPRI, Palo Alto, CA: 2014. 3002004681.

Event Logging:

- ***Requirements for Distributed Energy Resource Management Systems:*** *Status Data Logging and Saving*
- ***Requirements for Distributed Energy Resource Management Systems:*** *User Action Logging*

  The DERMS shall have a data store interface through which it can log and save monitored inverter data and control actions taken. This may be developed as an internal function of the DERMS or through an enterprise interface to another data-storage application.[55] The DERMS shall log all user actions, including time, location, user ID, method of access, and action taken. Logs shall be created in real-time, stored separately, and not accessible by the DERMS users.[56]

3.4.2 Islanded Functions

In this section discusses the functions for a microgrid controller in islanded mode with a bulleted list of the use case(s) that were used to determine the function and then a short description of the function derived from the use case(s) used.

Grid Tied to Islanding Transition:

- ***Microgrid Functional Use Case #F-3 Grid Connected to Islanding Transition – Intentional***

  The microgrid controller will manage resources to support ***planned*** and ***unplanned*** islanded operation. The maximum islanding time in Figure 3-5 and can be interpreted as the maximum time between the start of the voltage or frequency range and microgrid islanding from the area EPS.

  Planned intentional islanding involves controlling the energy flow at the point of common coupling (PCC) to near zero and separating from the grid. During planned intentional islanding a microgrid disconnects from the area electric power system (EPS) in a planned manner when the EPS is grid-connected and in a normal operating mode[57]. The transition to Island mode is based on a reasonably warning period, and can either be:

  a. *Command Planned Islanding*: Utility or operating entity requests the microgrid transition to an island mode at a specific time in the future with sufficient time for planning

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[55] *Requirements for Distributed Energy Resource Management Systems: An Assessment for Taiwan Power Company.* EPRI, Palo Alto, CA: 2013. 3002004363.

[56] *Ibid.*

[57] *Microgrid Functional Use Case #F-3, Grid Connected to Islanding Transition - Intentional.* ORNL: 2014. ORNL_UC_F-3.doc

b. *Scheduled Planned Islanding*: A scheduled tariff transition or operating agreement dictates that the microgrid transition to an island mode at a specific time.

c. *Unplanned/Unscheduled intentional islanding* will also needed to be supported by the microgrid controller. This could consist of two scenarios.

d. *Outage-Driven Unplanned Islanding*: A confirmed grid outage is detected by the recloser or switch at the PCC to open and start the unplanned/unscheduled islanding transition.

e. *Command Driven Unplanned Islanding*: A triggering event is detected by the monitoring platform to initiate the island recloser or switch at the PCC to open and start the unscheduled islanding transition. Alternatively the utility operation center receives the triggering event(s) and works with the Grid Operator to use DMS/SCADA to open the recloser.

Upon opening of the recloser at the PCC, the battery inverter receives the recloser open status and switches from current-source "Sc" mode to voltage-source "Sv" models.. Additionally, the microgrid optimizer and the DMS/SCADA receive the recloser open status to update their models. Under these conditions the microgrid controller should be able to shed loads and use storage to instantly balance generation and load when the PCC breaker is opened. As additional generation resources are brought on-line, any loads that were shed can be restored.

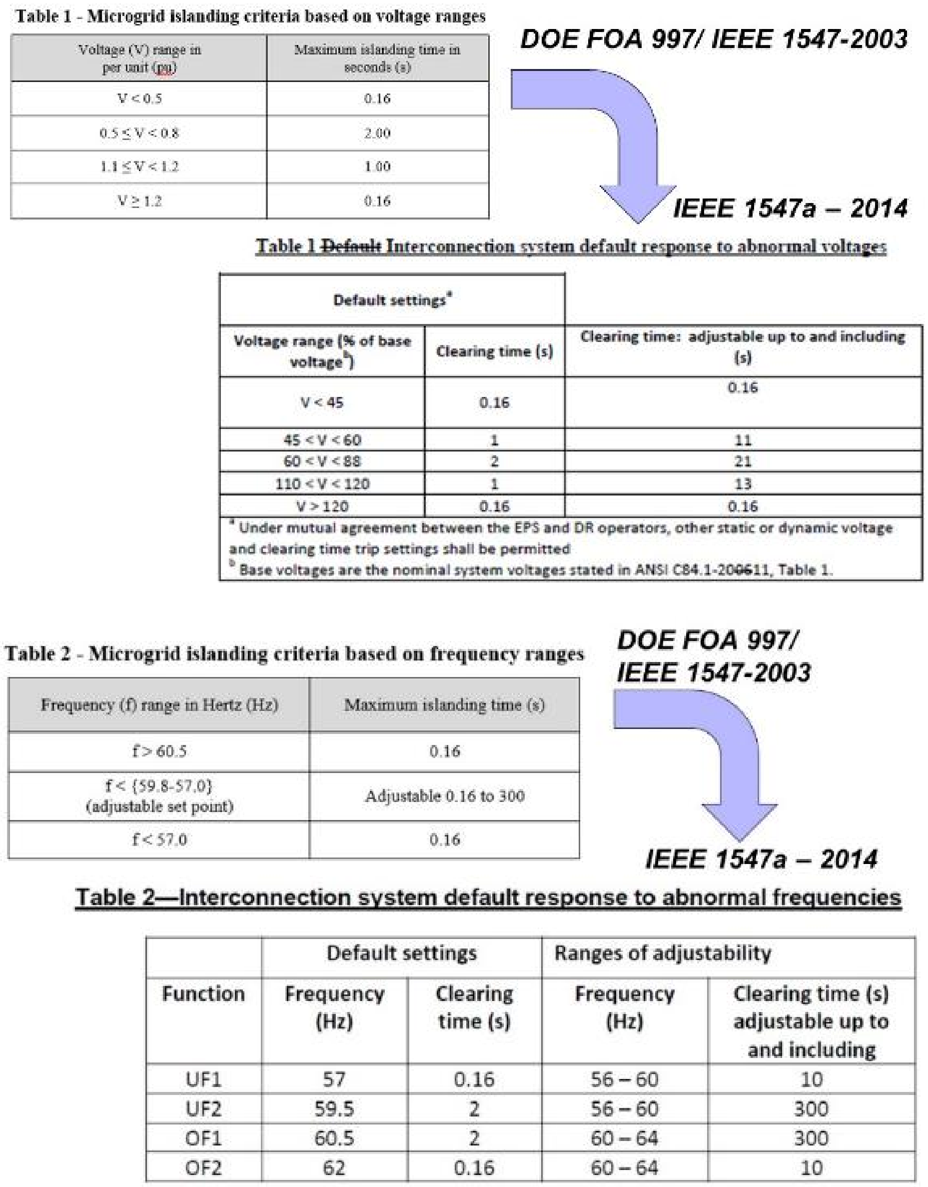

Table 1 - Microgrid islanding criteria based on voltage ranges

Voltage (V) range in per unit (pu)	Maximum islanding time in seconds (s)
$V < 0.5$	0.16
$0.5 \leq V < 0.8$	2.00
$1.1 \leq V < 1.2$	1.00
$V \geq 1.2$	0.16

Table 1 ~~Default~~ Interconnection system default response to abnormal voltages

Default settings[a]		
Voltage range (% of base voltage[b])	Clearing time (s)	Clearing time: adjustable up to and including (s)
$V < 45$	0.16	0.16
$45 < V < 60$	1	11
$60 < V < 88$	2	21
$110 < V < 120$	1	13
$V > 120$	0.16	0.16

[a] Under mutual agreement between the EPS and DR operators, other static or dynamic voltage and clearing time trip settings shall be permitted

[b] Base voltages are the nominal system voltages stated in ANSI C84.1-20~~06~~11, Table 1.

Table 2 - Microgrid islanding criteria based on frequency ranges

Frequency (f) range in Hertz (Hz)	Maximum islanding time (s)
$f > 60.5$	0.16
$f < \{59.8\text{-}57.0\}$ (adjustable set point)	Adjustable 0.16 to 300
$f < 57.0$	0.16

Table 2—Interconnection system default response to abnormal frequencies

Function	Default settings		Ranges of adjustability	
	Frequency (Hz)	Clearing time (s)	Frequency (Hz)	Clearing time (s) adjustable up to and including
UF1	57	0.16	56 – 60	10
UF2	59.5	2	56 – 60	300
OF1	60.5	2	60 – 64	300
OF2	62	0.16	60 – 64	10

Figure 3-5
Disconnection Requirements – Voltage and Frequency Disturbance

Islanding to Grid Tied Transition:

- ***Microgrid Functional Use Case #F-4 Unintentional Islanding to Grid-Connected Transition***
- ***Microgrid Functional Use Case #F-5 Islanding to Grid-Connected Transition***

Prior to reconnection of the microgrid system to an area EPS, monitoring should first indicate that the islanded microgrid is properly synchronized with the EPS. After an area EPS disturbance and subsequent microgrid islanding, reconnection shall not be initiated until the area EPS voltage is within Range B of the American National Standards Institute/National

Electrical Manufacturers Association (ANSI/NEMA) Standard C84.1-2006, Table 1,[58] the phase angle difference is within the limits defined by IEEE 1547™,[59] and the frequency range is between 59.3 Hz to 60.5 Hz.[60] The interconnection device may delay reconnection for up to five minutes after the area EPS steady-state voltage and frequency are restored to the ranges identified above. If an unscheduled event triggered the disconnection from the area EPS, reconnection should be delayed until it is verified that the area EPS is stable. If multiple islands exist, a strategy may be adopted to intentionally stagger the return of the islands. The microgrid must ensure that reconnection occurs when the frequency difference, voltage magnitude difference, and voltage phase angle difference between the area EPS and microgrid on either side of the microgrid switch are within the limits defined by IEEE 1547™.[61] For a microgrid with a rating between 1.5 and 10 megavolt-amperes (MVA), the reconnection requirements are shown in Table 3.

The microgrid controller will need to interface with phaser measurement units (PMUs) or power meters with phase angle and Δf (Hz) capabilities. The automatic synchronizing & reconnecting algorithms, which have been refined over the last 10 years in the field for networks between 208VAC and 150KV, take account of circuit breaker or circuit reconnection device closing times and the system's current configuration to calculate the estimated zero crossing allowing for microgrid reconnection as tested in the field within ±2°of the phase angle. Synchronization & reconnection can be achieved during adverse system conditions; the controller automatically adjusts to accommodate voltage differences and frequency differences with a configurable settings between 0% up to 20% in magnitude in voltage difference, and phase angle settings from 0 up to 10°, in a phase lock loop or slip frequency settings between 0.00 and 0.25 Df Hz

Table 3-9
Microgrid reconnection requirements

Microgrid rating (MVA)	Frequency difference (Δf, Hz)	Voltage difference (ΔV, %)	Phase angle difference (Δθ, °)
1.5-10	0.1	3	10

Steady-State Frequency Range, Voltage Range, and Power Quality

Depending on the nature of an area EPS, the ability of a grid-connected microgrid to affect the power quality inside the microgrid may be very limited. If the power quality supplied by the area EPS is insufficient for the critical loads,

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[58] ANSI C84.1 – 2006: Electric power systems and equipment – voltage ratings (60 Hz)

[59] *Ibid.*, Ref. 8

[60] *Ibid.*, Ref. 8

[61] *Ibid.*, Ref. 8

the microgrid may choose to island rather than attempt to improve power quality while grid connected. These requirements could also be used as a condition to determine when to island. An islanded microgrid in steady state operation must:

1. Maintain the frequency in the range 59.3 Hz < f < 60.5 Hz — a range consistent with the frequency range for an area EPS and suitable for most loads — barring customer-specific requirements that may override this range.
2. Maintain the voltage according to ANSI 84.1-2006 standards — specifically, the required voltage range for microgrid islanded steady-state operation is 0.95 pu<V< 1.05 pu at the PCC.
3. Maintain the power quality at the PCC in compliance with customer-specific requirements.

Voltage and Frequency Control:

- ***Microgrid Functional Use Case #F-1 Frequency Control***
- ***Microgrid Functional Use Case #F-2 Voltage Control (Grid- connected and Islanding)***
- ***Microgrid Interactive Use Cases #IA-8: Update Aggregated at PCC Real and Reactive Load-to-Frequency and Load-to-Voltage Dependencies in the Emergency Ranges***

This function is to balance the generation and loads in a microgrid to maintain the stability of the microgrid by controlling its frequency.[62] This function also regulates voltage at the PCC within a specified range. It is realized by one or more primary sources that are responsible for controlling frequency and/or voltage. It is determined by the microgrid SCADA if a microgrid source is operated as a primary source or other source, and the voltage setting point is sent by the microgrid SCADA to the primary sources.[63] The voltage and frequency function performs four tasks including contingency data submission by the DMS to the microgrid EMS, periodic and by event data submission from the microgrid EMS to the DMS/EMS about the microgrid real and reactive load-to-frequency and load-to-voltage dependencies in the emergency ranges, and logging and reporting for post-factum analyses. The objective of the function is to provide aggregated short-term real and reactive load-and-generation-to frequency/voltage dependencies at the PCC of advanced microgrids for the near-real-time and for the short-term look-ahead times to be used in the DMS/EMS contingency analysis and mitigation applications.[64]

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[62] *Microgrid Functional Use Case #F-1, Frequency Control.* ORNL: 2014. ORNL_UC_F-1.doc

[63] *Microgrid Functional Use Case #F-2, Voltage Control.* ORNL: 2014. ORNL_UC_F-2.doc

[64] *Microgrid Interactive Use Cases #IA-8: Update Aggregated at PCC Real and Reactive Load-to-Frequency and Load-to-Voltage Dependencies in the Emergency Ranges.* Smart Grid Operations Consulting on behalf of National Institute of Standards and Technology: 2015.

Frequency Control: Wave has built-in frequency control algorithms to support and maintain stable system frequency at various locations or islanding scenarios. The controller continuously monitors the health of the system frequency and available assets with frequency control capabilities to automatically dispatch for primary frequency control (referred to as frequency master). Wave controls the output of all non-frequency master assets in a frequency support mode that allows the frequency master asset(s) to operate in a configurable optimal operating range. The frequency control algorithm can also transfer frequency master responsibilities to different assets at the request of the operator (e.g. to take the frequency master asset down for maintenance), or automatically if more capable frequency master asset becomes available. Wave also has built-in under frequency and over frequency algorithms to manage emergency situations.

Voltage Control: Wave's grid connected voltage control methodology utilizes reactive power capabilities of assets in conjunction with traditional on-load tap-changer operation for advanced control of system voltage. Multiple nominal voltage levels can be configured and independently controlled. Voltage control areas are created automatically, based on nominal voltage levels and real-time awareness. System operators have complete control over voltage control setpoints and preferred operating range. The controller can transfer voltage master responsibilities to different assets during runtime by operator request or automatically if a larger more capable voltage master asset is available.

Power Quality and Reliability:

- ***Use Case 1: Facility Microgrid Reduces Outage Duration Following Natural Disaster Campus***
- ***Use Case 2: Facility Microgrid Reduces Outage Duration Following Natural Disaster Facility***
- ***Use Case 3: Utility Microgrid Controller Monitors Grid System Status and Exerts Control to Ensure Power Delivery for Critical Facilities***
- ***Microgrid Interactive Use Cases #IA-4: Updates of Capability Curves of the Microgrid's Reactive Power Sources***
- ***Sendai Use Case: Microgrid to Supply Power at Multiple Power Quality Levels (NEDO Sendai Project)***

The first two use cases describe a scenario where a natural disaster damages the electrical delivery system or gas supply and full restoration is estimated to take up to several weeks. All utility feeders to the campus/facility are disrupted, resulting in each of the following scenarios: 1) a power outage and a necessary transition to Island Mode or 2) the need to reallocate power to priority load resources on the campus or 3) the use of the diesel generators. Using the available generation and storage, including diesel generators, the microgrid controller campus/facility continues to operate as normally as possible actively allocating electric generation sources to the highest priority load. Periodic testing of the backup energy power systems and microgrid performed as part of the disaster preparedness exercises, ensures power reliability of the system when the need arises.[65]

In the third use case, the microgrid controller monitors grid status and responds to changes in grid condition. When directed or when grid conditions warrant, the microgrid controller transitions the microgrid to island mode. When the power grid is energized and stable, the microgrid controller transitions the microgrid back to normal mode. In island mode, the microgrid exerts control to provide power continuously to critical facilities. Critical facilities are connected to sections of the distribution grid which are automatically separated from the main grid prior to initiation of island mode. The microgrid controller monitors power quality and may command adjustments as required, for example to adjust Volt/VAR or phase imbalances. Depending on the design of the microgrid, power quality functions may be provided by physical distribution control devices, by the microgrid controller, or most likely by a combination of both. In normal mode, the microgrid controller monitors grid status and directs transitions to island mode for either reliability or economic reasons.[66]

Power quality and reliability is derived from periodic and event-driven updates of the DMS about the aggregated at the microgrid PCC nominal and operational capabilities of generating and absorbing reactive power by the reactive power sources of the microgrid and provides the DMS with relevant data for post-factum analyses when necessary. The objective of the function under consideration is to provide aggregated at the PCC near-real-time and short-term look ahead reactive power generating and absorbing capabilities of the microgrid reactive sources for the use by the DMS for the coordination of the DMS and microgrid operations.[67] Critical loads require higher levels of power quality than are supplied normally by the distribution utility. The Microgrid does this by utilizing DER and power from the distribution grid in a mutually complementary manner.[68]

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[65] *Use Case 1: Facility Microgrid Reduces Outage Duration Following Natural Disaster Campus.* EnerNex: 2015.

[66] *Use Case 3: Utility Microgrid Controller Monitors Grid System Status and Exerts Control to Ensure Power Delivery for Critical Facilities.* EnerNex: 2015.

[67] *Microgrid Interactive Use Cases #IA-4: Updates of Capability Curves of the Microgrid's Reactive Power Sources.* Smart Grid Operations Consulting on behalf of National Institute of Standards and Technology: 2015.

[68] *Sendai Use Case: Microgrid to Supply Power at Multiple Power Quality Levels (NEDO Sendai Project). 2012.*

Voltage Regulation:

- ***Microgrid Functional Use Case #F-2 Voltage Control (Grid- connected and Islanding)***
- ***Enterprise Integration Functions for Distribute Energy Resources:*** *Adjust Voltage Settings*

This function regulates voltage at the point of common coupling (PCC) within a specified range and is realized by one or more primary sources that are responsible for controlling voltage. It is determined by the microgrid SCADA if a microgrid source is operated as a primary source or other source, and the voltage setting point is sent by the microgrid SCADA to the primary sources.[69] This function allows for the target voltage settings of groups of DER to be adjusted. This could be useful in coordination with a conservation voltage reduction system.[70]

Protection

- ***Microgrid Functional Use Case #F-7 Microgrid Protection***

  A grid-connected microgrid must be capable of meeting the following protection requirements:

  1. An "external" fault (a fault on the area EPS side of the microgrid switch): The microgrid switch must open and interrupt the flow of fault current from the microgrid to the utility grid within 0.16 seconds of the fault occurrence
  2. The microgrid must prevent unintentional islands by opening the microgrid switch consistent with the requirement of IEEE 1547.2.
  3. An "internal" fault (a fault on the microgrid side of the microgrid switch): Internal faults will potentially draw large fault currents from the utility, through the microgrid switch, and to the fault. The microgrid must clear internal faults.

  An islanded microgrid is only subject to internal faults, and, thus, must clear internal faults.

  Microgrid protection schemes vary greatly depending upon the asset mix of induction, synchronous and inverter-based generation. Each type of generation supplies unique amounts of fault current and have different dynamic characteristics. Without mitigation, this creates protection coordination issues within a microgrid. Using modern utility grade protection devices is paramount to ensure safety of personnel and equipment. The proposed controller uses Multiple Group Protection setting schemes and

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[69] *Microgrid Functional Use Case #F-2, Voltage Control.* ORNL: 2014. ORNL_UC_F-2.doc

[70] *Enterprise Integration Functions for Distributed Energy Resources: Phase 1.* EPRI, Palo Alto, CA: 2013. 3002001249.

understanding of the current state of the electrical network to coordinate devices. By interfacing with a power system model, the microgrid controller can determine the available fault current and select the appropriate protection settings.

Economic Dispatch:

- ***Microgrid Functional Use Case #F-6 Energy Management (Grid-Connected and Islanding)***
- ***Microgrid Functional Use Case #F-8 Ancillary Services (Grid-Connected)***
- ***Microgrid Interactive Use Cases #IA-5: Updating Information on Microgrid Dispatchable Load***
- ***NEDO Systems Use Case #H2: Energy Management of Microgrid Under Islanding Operation that Makes Optimum Use of Biomass and Maintains Power Quality***
- ***NEDO System Use Case #A1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of City Gas as the Fuel and Mitigates Negative Effects of Intermittent Generators on Distribution Grid***
- ***NEDO System Use Case #K1: Energy Management by Configuring a Virtual Microgrid Using Public Communications Where Power is Supplied to End-Users While Achieving Simultaneous Balancing of Supply and Demand***

The economic dispatch function covers perhaps the widest range of objectives and goals.

Dispatch for microgrid survivability includes, but is not limited to:

1. While grid-connected, ensuring sufficient resources (e.g. generation and/or energy storage) are operating and available to support the microgrid's seamless transition to island mode.
2. While islanded, managing energy resources consistent with ensuring service to the microgrid critical loads for the duration of the islanded state.

Dispatch for economic operation may include, but is not limited to:

1. Optimization of the microgrid's energy consumption and generation against electric and natural gas tariffs.
2. Provision of services to the grid (area EPS), such as:
    a. Energy,
    b. Volt/VAR support,
    c. Frequency regulation,
    d. Spinning reserve,

e. Black start support, and

f. Demand response.

Dispatch for environmental performance includes reducing or limiting CO_2 emissions.

The microgrid controller automatically dispatches assets to meet the current operational criterion including maintaining local survival, supporting economic operations, minimizing environmental impacts and all combinations thereof. When grid connected the controller manages the local resources to ensure high power quality and readiness to island in case of emergency. Economic and environmental objectives issued by internal or external parties are evaluated and supported by dispatching additional assets (or modifying current asset set points) if capacity is available. While islanded, the controller's primary objective is to maintain critical loads and will automatically dispatch or shed generation and load assets as necessary. During extended island operations, the objectives may be modified to maximize survivability or to provide black start support. The allocation of assets is determined by taking an account of each asset's availability, capabilities (e.g., capacity and dynamic responsiveness) and operational constraints and matching these factors to the current list of objectives. Some common factors include active and reactive power capacity, response time, minimum and maximum operating times, calendar constraints, etc. The Wave environment manages a database of the asset parameters that can be easily updated via a user-interface to accommodate schedule changes or operational changes. The dispatch of assets may be configured to be automatic or to require operator acknowledgment.

Economic dispatch maintains power quality even when disconnected from the distribution grid and optimizes the use of biomass (digestion gas, wood biomass), while optimizing renewable energy. When disconnected from the distribution grid, the microgrid system is controlled by an EMS which determines the optimum generation schedule in accordance with load within the microgrid and also ensures power quality (voltage, frequency).[71] Economic dispatch optimizes the use of city gas while also optimizing renewable energy. It also functions to mitigate negative effects on the distribution grid with respect to demand-supply balance and power quality. The microgrid system is connected to the distribution grid at a single point and is controlled by the EMS which maintains the amount of power purchased from the distribution grid (power flow at PCC) to contribute to frequency control of the distribution grid and develops a generation schedule in accordance with the load within the microgrid.[72] A Virtual Microgrid

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[71] *NEDO Systems Use Case #H2: Energy Management of Microgrid Under Islanding Operation that Makes Optimum Use of Biomass and Maintains Power Quality.* 2012.

[72] *NEDO System Use Case #A1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of City Gas as the Fuel and Mitigates Negative Effects of Intermittent Generators on Distribution Grid.* 2011.

(VMG) supplies power to end-users while achieving simultaneous balancing of supply and demand. VMG is a concept for specific distributed energy resources and power receiving facility to balance the total supply and demand in each time period (simultaneous balancing). The use of renewable energy such as wind, PV and biomass can be maximized and the negative effects of output fluctuations on the commercial grid can be minimized through construction of a VMG. When constructing a VMG, there may be cases where generation and loads are dispersed and located at great distances from each other. It is desirable that the data entered into the system managing the simultaneous balancing (EMS) is time-stamped at the point of measurement to achieve simultaneous balancing under such cases. Additionally, it is possible to construct a cost-competitive VMG by employing existing public communications such as internet in an effort to avoid building costly dedicated lines.[73]

Load and Generation Following:

- ***Microgrid Interactive Use Cases #IA-6: Updates of the Information on Overlaps of Different Load Management Means Within Microgrids***
- ***NEDO Local Level Use Case #A2: Autonomous Decentralized Control of Microgrid Which Consists Only of Generating Equipment with Grid-Connected Inverters, Under the Islanding Operation***

The function performs periodic and event-driven information exchanges between the DMS and microgrid operator/microgrid EMS about the current amounts and setups of the effective load management means in the microgrid, and provides the DMS with relevant data for post-factum analyses when necessary. The objective of the function is to timely update load management models aggregated at the PCC of advanced microgrids for the near-real-time and for the short-term look-ahead times to be used in the DMS/EMS applications.[74] The second use case listed describes control function of microgrid system, which is comprised only of generating equipment with grid-connected inverters in islanded mode. This microgrid system is characteristic of the point that each generating equipment implements autonomous control without transferring signals among the paralleled inverters.[75]

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[73] *NEDO System Use Case #K1: Energy Management by Configuring a Virtual Microgrid Using Public Communications Where Power is Supplied to End-Users While Achieving Simultaneous Balancing of Supply and Demand.* 2011.

[74] *Microgrid Interactive Use Cases #IA-6: Updates of the Information on Overlaps of Different Load Management Means Within Microgrids.* Smart Grid Operations Consulting on behalf of National Institute of Standards and Technology: 2015.

[75] *NEDO Local Level Use Case #A2: Autonomous Decentralized Control of Microgrid Which Consists Only of Generating Equipments with Grid-Connected Inverters, Under the Islanding Operation.* 2012.

Load Shedding:

- ***Microgrid Interactive Use Cases #IA-1: Information Support for Coordination of EPS and Microgrid Load Shedding Schemes***

  The function performs data exchange between the DMS and microgrid EMS for the purpose of coordination of load-shedding remedial actions and logging and reporting for post-factum analysis. The function objective is to provide information to the DMS on the states and performance of the microgrid load and DER during emergency situations of DMS and to provide information to the operators of advanced microgrids on the possible emergency operating conditions of the DMS with respect to the emergency performance of the microgrid's load and DER.[76]

Dynamic Reactive Current:

- ***Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1***
  Reactive Power Dispatch of DER Groups

  This function allows the dispatch of reactive power from DER groups.[77]

User Interface and Data Management:

- ***Microgrid Functional Use Case #F-10 Microgrid User Interface and Data Management***

  This function defines the databases of a microgrid to organize and archive both real-time and non-real-time data. It also defines the user interfaces and accessibility of different actors.[78]

Additions to State/Status Monitoring:

- ***Use Case 4: Utility Bills for Microgrid Services***
- ***Use Case 5: Utility Tests Community Microgrid***
- ***Microgrid Interactive Use Cases #IA-7: Updating Dependencies of the Microgrid Operational Model on External Conditions***

  Interval metering of all facilities on the microgrid provides information on usage for billing. Generation meters and potentially an interconnection switch meter provide data required for settlement with the microgrid generation owner. The microgrid controller provides time-stamped data on the microgrid's mode of operation to facilitate accurate billing and

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[76] *Microgrid Interactive Use Cases #IA-1: Information Support for Coordination of EPS and Microgrid Load Shedding Schemes.* Smart Grid Operations Consulting on behalf of National Institute of Standards and Technology: 2015.

[77] *Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1*. EPRI, Palo Alto, CA: 2014. 3002004681.

[78] *Microgrid Functional Use Case #F-10, Microgrid User Interface and Data Management.* ORNL: 2014. ORNL_UC_F-10.doc

settlement.[79] Microgrid functionality is verified in normal mode, island mode, during mode transition and during a simulated emergency situation. During the initial commissioning, microgrid functionality is verified against the utility's and the vendor's specifications. Following system engineering best practices, requirements defined in the microgrid use cases are verified.[80] The function also performs periodic and event-driven information exchanges between the DMS and microgrid EMS about the aggregated at the PCC dependencies of the operational model of microgrid on external conditions. Periodic and event-driven updating of the external conditions is conducted by the DMS and other parties to provide the DMS with relevant data for post-factum analyses, when needed. External conditions considered include weather conditions, real-time dynamic pricing, volt/VAR support requests from the DMS, and very large scale events.[81]

3.5 Extracted Requirements

Functions, discussed above, address higher level capabilities of a microgrid controller. Requirements provide a detailed approach to the components of the functions. Requirements may range from a high level abstract statement of service or a statement of a system constraint to a detailed mathematical functional specification. There are functional and technical requirements. Functional requirements are captured in this document, as they are derived from use cases, and describe system behavior. Technical requirements:

- Include constraints on the services or functions offered by the system such as timing constraints, constraints on the development process, standards, etc.
- Define system properties and constraints e.g. reliability, response time and storage requirements. Constraints are I/O device capability, system representations, etc.
- Process requirements may also be specified mandating a particular system, programming language or development method

While the specific requirement for each function differs, they follow a similar process which includes:

1. Microgrid controller EMS sends status - this is a common message
2. Microgrid controller EMS receives commands to do something (generation, state of charge, etc.)
3. Microgrid controller EMS reports exceptions
4. Microgrid controller EMS validates commands it has received.

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[79] *Use Case 4: Utility Bills for Microgrid Services.* EnerNex: 2015.

[80] *Use Case 5: Utility Tests Community Microgrid.* EnerNex: 2015.

[81] *Microgrid Interactive Use Cases #IA-7: Updating Dependencies of the Microgrid Operational Model on External Conditions.* Smart Grid Operations Consulting on behalf of National Institute of Standards and Technology: 2015.

In the case of the requirements discussed below, the basic messages for status and commands exist. However, for more advanced functionality, e.g. black start or anything with sequencing, messaging is a gap as messages are single actions, including validation of operation, not multiple step. In some situations, this gap can be managed through DMS; however, in the future messages will need to be expanded.

The information provided in this section includes requirements derived from the functions addressed above. The sections are broken down into grid tied and islanded modes of operation. Sections 3.4.1 and 3.4.2 provide a selection of the functional requirements deemed most relevant and useful for the use of microgrid controllers. Additional grid tied and islanded requirements are in Appendix A.

3.5.1 Grid Tied Requirements

This section discusses the requirements for a microgrid controller in grid tied mode with a bulleted list of the use case(s) that were used to determine the function and the requirements derived from the function for use case(s) used.

Connect/Disconnect – Non-Islanding:

- ***Enterprise Integration Functions for Distribute Energy Resources:***
  [On/Off Control]

  A foundational requirement for DER enterprise integration is a way to represent individual DER plants in the system model. This is necessary so that it is possible to explore the model and discover the DER that exist and their basic characteristics so that groups can be logically formed. A comprehensive representation of DER in a system model (e.g. in CIM or MultiSpeak) may have a wide range of parameters, each useful to certain utility departments for specific purposes. The items identified here are considered a required subset of this data, needed to support the basic monitoring and management services identified in this document. It is anticipated that this minimum set of parameters would be expanded as additional enterprise integration functions are identified.

  Parameters to represent individual DER, supporting application integration:

  1. DER Name
  2. DER Type
  3. DER Physical Address
  4. DER Geographical Location
  5. DER Owner
  6. DER Contract/Agreement
  7. DER Terminal and Phase(s)
  8. DER Watt Rating

9. DER VAR Rating
10. DER VA Rating
11. DER Storage Watt-hours
12. DER Notification
13. DER Ramp Time.

The enterprise integration interest group found that a process for identifying the intended set of DER was a necessary precursor to status monitoring, capabilities discovery, and dispatch functions. This is necessary so that it becomes possible to monitor and manage DER at a higher level, with a focus on the attributes, impacts, and opportunities as they relate to the distribution system rather than individual DER plants or devices.

DER grouping requirements:

1. Group Size
1. Grouping by Power System Level
2. Grouping According to Other Attributes.

The method by which the present status of DER groups may be exchanged between software applications in an enterprise integration environment requires that the referenced DER group definition exists in both the status-requesting and status-providing entities. The makeup of the group could have been defined by the requestor, the provider, or any other entity, and could have been a manual or automated process.

The "installed capabilities" function is intended as a mechanism for the exchange of information between software applications in an enterprise environment. This function is not intended to relate directly to communication with DER in the field, or to provide a mechanism by which DER capabilities might be automatically registered into the utility system (plug-n-play DER). An initial discovery process is assumed to have taken place. This initial process could occur in a number of ways, all of which are out of scope for this body of work:

- A human process by which DER capabilities data is manually entered into the system model
- An automated process by which newly connected DER are discovered and described in a plug-n-play fashion
- Any number of other methods.

Once the capabilities are known to some enterprise application, a subsequent process may occur in which these capabilities are shared between software applications. The subsequent process is intended to address this function.

The previously defined method of using arbitrarily defined groups is also used for real power dispatch. It requires that the referenced DER group definition (i.e. the list of which DER make up the group) is known and agreed to by both the real-power-requesting and real power-providing entities. The makeup of the group could have been defined by the requestor, the provider, or any other entity, and it creation could have been a manual or automated process. Group creation (required) and status monitoring (optional) could occur immediately before the real power dispatch (request and reply) or any time prior. The group definitions used for real power dispatch would notionally be the same as those used for status monitoring.

The present status for real and reactive power includes three parts: a present value, a maximum, and a minimum range of adjustability. Forecasting is relevant for the maximum and minimum values. Forecasting is not relevant for the present value because it is dispatchable and bounded only by the maximum and minimum. Forecasts may involve varying degrees of uncertainty. To represent this, the forecast for a given parameter can be described as an envelope, a range of uncertainty, possibly widening further into the future as the forecast becomes less certain. The present maximum and minimum values are labeled at the left hand side. Because they reflect the present state, they are specific, known values. But looking into the future, the forecasts for these quantities may be represented through a widening envelope, as illustrated by the red shaded areas.

Maximum Generation Level Control:

- ***SGIP Open FMB Microgrid Use Cases: Microgrid – Optimization***

  The sequential steps listed below were developed for the goal of microgrid optimization.

  1. The critical load is always on and there is an optional human operator who may observe operations of microgrid and override as necessary
  2. There is a higher level controller for the grid to the microgrid is connected, such as DMS to manage and control the overall distribution grid
  3. The dispatching is completed periodically during system configuration.
  4. SCADA systems polls and/or subscribes to open field message bus data periodically.
  5. Microgrid load forecast runs on a periodic basis and publishes updated weather forecasts on a periodic basis.
  6. Power system disturbance detected by relaying protection scheme that operates the grid.
  7. Solar panel inverter is always on during daylight. Microgrid optimizer able to dispatch inverter up to current maximum capability of solar panels
  8. Battery inverter is always on. Microgrid optimizer able to dispatch inverter up to current maximum capability of battery.

The requirements include, the system shall:

1. Validate the status of the critical load(s)
2. Allow for a manual override
3. Prioritize commands issued from a higher level controller
4. Validate the status of smart inverters
5. Dispatch lower level DER, to the capacity of the storage or generation capacity available
6. Provide status update to SCADA/EMS/DMS
7. Read periodic update in load forecast from microgrid load forecast
8. Read periodic update in weather forecast from microgrid weather forecast
9. Defer control to power system protection scheme (relaying protection scheme)
10. Validate successful completion of dispatching.

Storage Management:

- ***Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1:***
  [DER Group Creation]

  Regardless of where the DER management function is ultimately deployed (a dedicated DERMS or other) it will be necessary for the DER management function to share information with other relevant systems at the utility. What will be needed are extensions to existing standards to support the new DER functions. In terms of communication from the enterprise to devices in the distribution network, there is an expectation that the DERMS will employ either a proprietary vendor interface, or interfaces based on standards such as the IEC 61850 and Distributed Network Protocol (DNP3). What happens inside the DERMS will be up to each vendor and how the DER are managed will also be up to a given vendor. It is neither beneficial nor intended by this initiative to standardize the inner workings and DER optimization algorithms that might be employed inside a DERMS. The focus of this work is to enable communication from the DERMS to the enterprise using utility integration standards, CIM and MultiSpeak.

- ***NEDO System Use Case #H1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of Biomass and Mitigates Negative Effects of Intermittent Generators on Distribution Grid***

  The sequential steps listed below were developed to optimize the use of biomass while reducing the associated consequences of using generators.

  1. The EMS begins supply plan development and weekly weather forecast information is acquired by EMS.

2. Past demands and output records data is acquired by EMS.
3. Electricity and heat demand based on weekly weather forecasts and past electricity and heat demand records data are forecasted by EMS.
4. PV and WT outputs are forecasted by EMS based on weekly weather forecast and past output records data.
5. Information about the remaining amount of digestion gas and wood chips is acquired by EMS along with the battery SOC.
6. A supply plan is developed by EMS based on electricity & heat demand forecast, remaining fuel level, and the battery state of charge (SOC). Based on this information, optimum scheduling is commanded by EMS and power demands of load are acquired by EMS.
7. PV, WT, and gas engine outputs are acquired by EMS.
8. Information about the remaining amount of digestion gas and wood chips, digester temperature, power flow at the PCC, and Charge/discharge power of battery is acquired by EMS.
9. The command for supply plan is provided by EMS.
10. The dispatch command for gas engine and wood chip boiler and charge/discharge power dispatch command are provided.
11. The EMS provides the gas engine with the LFC command and battery with charge/discharge LFC command so that the power flow at the PCC conforms to the purchasing power determined in the supply plan (Stage 1).
12. P, Q and V of each phase in PCC_RTU and MainPlant_RTU is acquired by EMS.
13. The negative phase sequence current (amplitude, phase) is calculated by EMS and provides PV & PCS with I2 dispatch command.

The requirements include, the system shall:

1. Provide digestion rates of gas and wood chips
2. Provide battery SOC and rate of change
3. Provide digester temperature
4. Provide load, PV, WT, and gas engine outputs
5. Receive and process LFC commands to gas engine and charge/discharge LFC commands
6. Receive and process dispatch command for gas engine and wood chip boiler
7. Receive and process dispatch command for battery storage.

Volt/VAR Management and Power Factor:

- ***Requirements for Distributed Energy Resource Management Systems:*** *[Volt-VAR Management] And [Power Factor Management]*

DERMS Interface Requirements:

Field Communication Interface: DERMS must provide a downstream communication interface to DER in the field which may be done either via integrated communications or through external communication interfaces. The result is the same with the difference being just an implementation preference. Integrated communications are likely only practical if DER are SCADA-connected, such as may be the case for commercial and utility scale DER. In this case, the DERMS may have standard integrated SCADA capabilities, supporting such protocols as the DNP3 or IEC 61850 MMS. Alternatively, a DERMS may utilize external communication software such as a dedicated SCADA communication interface, an AMI headend, third party cloud service or other. In this case, the DERMS has only a limited number of downstream interfaces and proprietary API's could be utilized if standards do not address these links. In either case, the final downstream communication to the must be an open standard if the process of integrating the many types and brands of products is to be practical and manageable over the long term.

Enterprise Integration Interface: The DERMS must have an enterprise integration interface. This interface is used to integrate the DERMS with DMS and other enterprise applications. Each utility's enterprise architecture is unique, with various applications existing and various functionalities grouped within each application. Regardless of how it is packaged, DERMS must have an enterprise interface to allow integration with other applications. This enterprise interface shall be standards based, utilizing the IEC Common Information Model (CIM). The global utility industry has been working to develop standard enterprise-level functions and messages for enterprise interactions related to DER management and monitoring. These functions are higher-level, less specific to a single DER, and more oriented to groups of DER as they associate with levels of the power system (e.g., by feeder, by section, by phase).

Human Interface: The DERMS shall include a human interface through which users can manage and monitor the overall DER population. Users of various types (various roles within the utility) shall be able to securely access the DERMS with access and permissions that are limited and consistent with their role. DERMS administrators shall be able to setup user access and to flexibly configure the range of permissions extended to each user.

Data Storage: The DERMS shall provide secure storage for all user-created settings and for all monitored data. The latter of these is discussed in more detail later in this document and results in large quantities of data. The value of saving this data lies in the analytics that they enable, including after-the fact failure and event analysis, trending, settlement with DER owners, dispute resolution, and optimization of DER management algorithms. In addition, user-created data such as schedules, function curves and full configuration settings shall be storable and reusable. To facilitate this, the DERMS shall provide organized methods for storage of such settings, and search-ability by file name, user, creation date, last date of use, and DER to which the settings have been applied.

DERMS Management Capability Requirements:

Time Synchronization: The DERMS shall be capable of synchronizing its sense of time with that of the overall IT system. This may be handled in a number of ways. In most cases, enterprise applications acquire their time from the servers and operating systems on which they are running, and these servers are synchronized via common means with other onsite systems. Alternatively, this may be accomplished via a time-synchronization message that is received by the DERMS via CIM messages from a time-master (standalone or part of some other application) on the enterprise system. This time reference shall be used by the DERMS for all scheduled activities and for time-stamping of all received or logged data. The DERMS shall be capable of actively managing the time of DER in the field, based on the DERMS time. For devices that are time-settable, the DERMS shall regularly (daily) synchronize the time of each device to the DERMS/system time. In some cases, a DER might have a local time source, such as GPS-based time. In both cases, the DERMS shall compute and record the difference between the DERMS time and the DER time each day and shall provide notifications if this time difference exceeds a pre-determined utility limit.

Device Grouping: The DERMS shall support the organization of DER into logical groups and management by group. It shall be possible to form groups and to associate inverters with groups via either the human interface (manual group creation and editing) or through the enterprise integration interface. By way of the enterprise integration interface, other software applications, such as a DMS may determine how DER are to be grouped so that it can call on these groups in a way that is properly aligned with the other controls involved in overall feeder optimization. In most utility implementations, grouping will be done either by the DMS or at the DERMS, but not both. If grouping is done at the DERMS, then the other enterprise applications such as DMS must be able to discover what groups exist and what devices are members of each group. In the event that DER group creation is performed manually, the means by which the human operator identifies and determines how to group and which DER to assign to each group is out of scope. In other words, the operator can create groups as desired.

Curve Creation and Saving: The standard smart inverter functions include a number of configuration settings that are arrays of points. These arrays of x-y point pairs create piece-wise linear “curves” that define how inverters should respond to locally observable parameters. The DERMS should provide users with a means to create, name, and save a wide range of curves for each of the smart inverter functions that are curve-based. This means would be graphical and easy to use and verify. Accurate curve creation is critical, and these means are intended to help ensure that the intended behavior is achieved. It is not easy to tell what a curve looks like from a text list of x-y points. The DERMS must provide a way to save curves in a file/library that can be drawn from later when overall inverter configurations are produced. It could be, for example, that a utility would have certain curves that are repeatedly used for certain inverter sizes, for certain feeders, or for certain DER asset owners.

Schedule Creation and Saving: The IEC standard inverter functions include the ability to download time-based schedules to inverters. The scheduling mechanism is flexible and allows for many different inverter functions to be scheduled. For example, an inverter may have several complete sets of configuration data stored in it. A schedule (daily, weekly, etc.) can be created and sent to the inverter that instructs the inverter to switch from one configuration to the other at times throughout the schedule period. This feature can be useful in minimizing communication system burden in cases when there is a predictable, recurring need for configuration changes. For example, one inverter configuration may be desired during weekday on-peak periods, a second configuration during weekday off-peak periods, and a third configuration on weekends. The DERMS shall provide a GUI through which a user can create, name, and save schedules. The DERMS shall be capable of sending these schedules to groups of inverters.

Status Data Logging and Saving: The DERMS shall have a data store interface through which it can log and save monitored inverter data and control actions taken. This may be developed as an internal function of the DERMS or through an enterprise interface to another data-storage application.

Optimization and Utility Business Priorities: A range of factors may be taken into account by a DERMS in order to determine how to best utilize DER. Recently, some utilities have used DMS that perform integrated volt/VAR optimization (IVVO). These optimizations involve on-load tap changers (LTCs), capacitors, line regulators, and switches, along with sensors for monitoring various voltages and power flows. A DMS IVVO seeks to identify the optimal settings for all the distribution controls. The meaning of "optimal," in this case, depends on the business priorities of TPC.

Scalability: The DERMS shall be capable of tracking, monitoring, and managing the total number of downstream DER, including those of all scales (utility to residential). Actual utility decisions to integrate the more numerous small systems may be deferred for some time, but DERMS should be scalable/extensible to cover all. In some architectures, a single central DERMS might be used. In this case, the total number of managed DER might be very large, millions potentially. In other architectures, DERMS might be handled at the substation, circuit, or feeder level. In this case, the total number of managed DER might be low, such as tens or hundreds.

Security: As the quantity of grid-connected DER increases and the degree of utilization of these resources rises, the communication and control systems become more critical. Given the present environment for high-penetration DER, particularly for solar photovoltaic systems, it is prudent to develop DERMS and the surrounding communication systems with security that is appropriate for critical operations. A comprehensive cyber security plan is outside the scope of this document; however, primary points of consideration are identified in the following sections.

Encryption: Communications, both upstream and downstream of the DERMS, shall be encrypted. The recommended standards for these interfaces include extensive cyber-security content.

User Security: The DERMS shall provide appropriate user security consistent with utility policy for DMS and other operational applications. This includes physical security for access to the servers and related user interfaces. The DERMS shall support verification of users via credentials, with proper access levels based on staff role (monitoring only, control actions, etc.).

- ***Microgrid Interactive Use Cases #IA-2: Coordination of Volt/VAR Control in Connected Mode Under Normal Operating Conditions***

  The steps listed below were developed in an effort to assist with coordination of volt/VAR control.

  1. The microgrid EMS should provide the DSO/DMS with near-real time and short-term look-ahead aggregated at the PCC VARs as a function of the PCC voltage under current microgrid volt/VAR control setups.
  2. Microgrid operator/microgrid EMS may inform the DSO/DMS about the desired voltage range at PCC to support the chosen objective under different ambient and load conditions.
  3. The DSO/DMS should inform the microgrid about the possible range of voltages at the PCC in a given timeframe.
  4. The DSO/DMS should provide the microgrid operator/microgrid EMS with its requirements/requests for the volt/VAR support of the DMS operations.
  5. The microgrid operator/microgrid EMS should provide the DSO/DMS with the impacts of the change of the volt/VAR control setup.
  6. The microgrid operator/ microgrid EMS should provide the DSO/DMS with the setup of the microgrid reactive sources for the mitigation of the DER intermittencies in an aggregated at the PCC manner. It should be noted that some of the conditions for volt/VAR coordination can be defined in the interconnection requirements and/or in other contractual agreements.
  7. The conditions for the VAR curves of the microgrid are changing in near-real time and as a result the microgrid EMS should update the aggregated at the PCC VAR curves on by exception basis.
  8. The structure of the exchanged data should support multi-dimensional, non-monotonous dependencies, command/request formats, and metrics of data uncertainty. The dependencies should cover practical ranges of the independent variables under normal operating conditions.

State/Status Monitoring:

- ***Requirements for Distributed Energy Resource Management Systems:***
  [Inverter Status Monitoring]

  See above (Requirements for Distributed Energy Resource Management Systems) for detailed requirements.

- ***Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1:***
  [Status Monitoring of DER Groups]

  See above (Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1) for detailed requirements.

3.5.2 Islanded Requirements

This section discusses the requirements for a microgrid controller in islanded mode with a bulleted list of the use case(s) that were used to determine the function and the requirements derived from the function for use case(s) used.

Grid-Connected to Islanding Transition (Intentional and Unintentional):

- ***Microgrid Functional Use Case #F-3: Grid Connected to Islanding Transition – Intentional***

  The sequential steps listed below were developed to clearly outline the components of the process for intentionally transitioning a microgrid from grid tied mode to islanded mode.

  1. A bid is submitted after which the market dispatch is received.
  2. The microgrid economic dispatch is calculated and the measurement and control commands are updated.
  3. Control commands are then sent and executed and the islanding request is sent.
  4. The islanding request response is received and islanding commands are calculated, sent, executed, and validated with a response.
  5. The microgrid switch open command is then sent and the microgrid switch opens and the status to primary sources is sent.
  6. Voltage and frequency control are maintained and lastly the microgrid switch open is confirmed.

  The requirements include, the system shall:

  1. Receive market dispatch from the EMS.
  2. Update statuses to the EMS regarding voltage, frequency, etc.
  3. Receive and process an islanding command
  4. Validate microgrid islanding.

Islanding to Grid-Connected Transition:

- ***Microgrid Functional Use Case #F-4: Unintentional Islanding to Grid-Connected Transition***

  The sequential steps listed below were developed to clearly outline the components of the process for the unintentional transitioning a microgrid from grid tied mode to islanded mode.

  1. A bid submission is sent and the market dispatch is received.
  2. The microgrid economic dispatch is calculated and the measurement and microgrid economic dispatch are updated.
  3. Control commands are then updated, sent, and executed followed by grid disturbance detection.
  4. The microgrid switch is opened and the status is sent.
  5. Frequency and voltage control execution is completed.
  6. The microgrid control commands are then updated, sent, and executed.
  7. The microgrid status is sent and the microgrid economic dispatch is sent.

  The requirements include those listed above in the Grid Connected to Islanding Transition use case.

- ***Microgrid Functional Use Case #F-5: Islanding to Grid-Connected Transition***

  The sequential steps listed below were developed for a microgrid transition from islanded mode to grid tied mode.

  1. The measurement is updated and the microgrid economic dispatch is updated.
  2. The control commands are updated, sent, and then executed.
  3. The economic dispatch is calculated.
  4. The APS normal is detected and the APS normal signal is sent.
  5. A re-connection request is sent and a response is received.
  6. A re-synchronization dispatch command is sent and then executed.
  7. The microgrid switch is closed and the status is sent.
  8. Grid-connected control mode is then initiated and microgrid control commands are sent and executed.
  9. A bid is submitted and the market dispatch is received.
  10. The microgrid economic dispatch is calculated.

  The requirements include those listed above in the Grid Connected to Islanding Transition use case.

Economic Dispatch:

- ***Microgrid Functional Use Case #F-6: Energy Management (Grid-Connected and Islanding)***

  The sequential steps listed below were developed specifically for energy management when the microgrid is either grid tied or islanded mode.

  1. Completion of the day-ahead bidding and scheduling command, the day-ahead demand forecast, and the day-ahead renewable output forecast.
  2. The measurement is updated.
  3. The microgrid measurements and battery SOC are acquired and the market bids are developed.
  4. A bid is submitted and the market dispatch is received.
  5. The microgrid unit commitment is developed and commands are sent.
  6. The short-term economic dispatch command is sent, the short-term demand is forecasted, and the short-term renewable output is forecasted.
  7. The microgrid economic dispatch is developed, commands are sent, and then it is updated.
  8. Control commands are then updated and sent.
  9. The real-time OPF Command is then sent.
  10. The microgrid real-time OPF dispatch commands developed, sent and then updated.

  The requirements include those listed above in the Grid Connected to Islanding Transition use case.

- ***Microgrid Functional Use Case #F-8: Ancillary Services (Grid-Connected)***

  The sequential steps discussed below were designed to easily coordinate ancillary services between the microgrid and available resources.

  1. The ancillary service contract negotiating command is sent.
  2. The microgrid EMS contract updates and contracts are sent to the market operator until contract acceptance by the market operator.
  3. The market operator the sends a response or acceptance confirmation to the microgrid EMS.
  4. Microgrid ancillary service contracts are sent to microgrid SCADA and then distributed to corresponding units and loads.
  5. The day-ahead ancillary service bidding and scheduling command is sent and the day-ahead demand and renewable output is forecasted.
  6. The measurement is update and the microgrid measurements and batter SOC are acquired.

7. Market bids of ancillary services are developed and a bid is submitted.
8. The market dispatch is received and the microgrid economic dispatch updated and commands are sent.
9. The hour-ahead ancillary service bidding and scheduling command is sent, and the hour-ahead demand and renewable output is forecasted.
10. The system accepts ancillary service bids in day-ahead markets and the hour-ahead market bids of ancillary services are developed.
11. Hour-ahead market dispatch is then received and ancillary services are requested.
12. The measurement is updated and microgrid dispatch commands are developed and sent.
13. Control commands are executed and the execution confirmation is requested.

The requirements include, the system shall:

1. Receive market dispatch from the EMS
2. Update statuses to the EMS regarding voltage, frequency, SOC, capacity, etc.
3. Receive and process dispatch commands
4. Validate dispatch commands executed.

- ***Microgrid Interactive Use Cases #IA-5: Updating Information on Microgrid Dispatchable Load***

  The sequential steps below are intended to provide updated information regarding microgrid dispatchable loads.

  1. The DSO/DMS may request that the microgrid EMS change some of the conditions that impact the dispatchable load of the microgrid to meet the DMS needs for the dispatchable load.
  2. The microgrid EMS should provide the DSO/DMS with the impacts of the change of the conditions, if requested.
  3. The microgrid operator/ microgrid EMS should provide the DSO/DMS with near-real time and short-term look-ahead aggregated at the PCC dispatchable real and reactive load dependencies on the PCC voltage under current and short-term look-ahead microgrid volt/VAR control setups, DER and other reactive sources loading, and other relevant operating conditions significantly impacting the dependencies.
  4. The microgrid operator/ microgrid EMS should exchange with DSO/DMS the information on the conditions under which the dispatchable load can be utilized.
  5. The DSO/DMS should inform microgrid about the possible range of voltages at the PCC in a given timeframe.

6. The DSO/DMS should provide the microgrid operator/microgrid EMS with its requirements/requests for the utilization of the dispatchable load.
7. The DSO/DMS should provide the microgrid operator/microgrid EMS with its requirements/requests for the increase of the dispatchable load when necessary.
8. The microgrid operator/ microgrid EMS should exchange with DSO/DMS the information on the impacts of the changes of the microgrid operating conditions, if such are required by the DMS to increase the amount of dispatchable load.
9. The microgrid operator/ microgrid EMS should provide the DSO/DMS with the assessment of the degree of uncertainty of the dispatchable load (the degree of uncertainty of the utilization of the dispatchable load can be derived by the DSO/DMS based on the prior performance).
10. The conditions for the dispatchable load of the microgrid DERs are changing in near-real time. Hence, the microgrid EMS should update the aggregated at the PCC dispatchable load on by exception basis and submit them to the DSO/DMS for the use in the DMS and EMS (via TBLM) applications.
11. The structure of the exchanged data should support, non-monotonous dependencies, command/request formats, and metrics of data uncertainty. The dependencies should cover practical ranges of the independent variables under normal operating conditions.

The requirements include, the system shall:

1. Provide status updates upon request from the microgrid EMS
2. Provide status of DER on an exception basis
3. Execute the control commands from the microgrid EMS.

- ***NEDO Systems Use Case #H2: Energy Management of Microgrid Under Islanding Operation that Makes Optimum Use of Biomass and Maintains Power Quality***

  The sequential steps discussed below detail information regarding the optimization of biomass while maintaining power quality.

  1. The EMS developing a supply plan.
  2. Weekly weather forecast information is acquired by the EMS and past demand (electricity, heat) and output (PV, WT) records data is acquired by the EMS.
  3. The EMS forecasts electricity & heat demand based on weekly weather forecast and past electricity & heat demand records data.
  4. The EMS also forecasts PV & WT output based on weekly weather forecast and past output records data.

5. Information about the remaining amount of digestion gas and wood chips is acquired by the EMS along with the battery SOC.
6. The supply plan is developed by the EMS based on the electricity and heat demand forecast, remaining fuel level, and the battery SOC.
7. The EMS then commands for optimum scheduling.
8. The EMS acquires the following information:
    - Power demands of load
    - PV output
    - WT output
    - Gas engine output information
    - Remaining amount of digestion gas and wood chips
    - Digester chamber temperature
    - Charge/discharge power of battery.
9. The command for the supply plan, the dispatch command for gas engine and wood chip boiler; and charge/discharge power dispatch command are all provided by the EMS.
10. The voltage deviation associated with load change is detected by Gas E, battery, and PCS. 11. Gas E and battery are provided with reference voltage command by the EMS.
11. The reactive power dispatch command is provided by battery and PCS so as to maintain voltage at the reference voltage.
12. The fringe component of islanded grid's frequency is then acquired by the EMS. The EMS provides Gas E with a dispatch command and BAT & PCS with charge/discharge dispatch command so as to maintain frequency at the reference frequency.
13. The cyclic component of the islanded grid's frequency is acquired by battery and PCS.
14. The Charge/discharge power dispatch command is provided by battery and PCS so as to maintain frequency at the reference frequency.
15. , Q, and V of each phase in MainPlant_RTU is acquired by the EMS.
16. The negative phase sequence current (amplitude, phase) is calculated by the EMS and provides PV & PCS with an I2 dispatch command.

The requirements include, the system shall:

1. Provide status updates upon request from the microgrid EMS
2. Provide status of DER on an exception basis
3. Execute the control commands from the microgrid EMS.

- ***NEDO System Use Case #K1: Energy Management by Configuring a Virtual Microgrid Using Public Communications Where Power is Supplied to End-Users While Achieving Simultaneous Balancing of Supply and Demand***

  The sequential steps are broken down into two options including the development of a generation and power purchase plan and supply/demand control. The two different sets of steps are described below.

  Development of Generation and Power Purchase Plan Based on Demand and Generation Forecasts:

  1. Long-term forecast are started by the EMS and weekly weather forecast information is acquired by the EMS.
  2. Past demand patterns are read by the EMS.
  3. Long-term forecasts are conducted by the EMS based on weekly weather forecast and past demand patterns.
  4. Short-term forecasts are started by EMS and a weather forecast for the day and the next day are acquired by the EMS.
  5. Past demand patterns are read by the EMS and short-term forecasts are conducted by the EMS based on the weather forecasts for the day and the next day and past demand patterns.
  6. Generation scheduling is developed by the EMS.

  Supply/Demand Control to Achieve Simultaneous Balancing:

  1. The power consumption of a load is acquired by the communications server.
  2. Generation power of intermittent renewables is then acquired by the communications server.
  3. Generation power of controllable generators is acquired by the communications server and data is obtained from RTUs in chronological order organized by the communications server.
  4. The supply-demand imbalance is calculated by communication server and then the supply-demand imbalance is transmitted by the communication server to the EMS.
  5. The output reference of controllable generators is generated by the EMS based on supply-demand imbalance and generation scheduling.
  6. The output command is transmitted by the EMS to the controller of the controllable generator.

  The requirements include, the system shall:

  1. Provide updates of storage and renewables
  2. Receive and process output commands from the EMS
  3. Validate execution of output commands to the EMS.

- ***NEDO System Use Case #A1: Energy Management of Grid-Connected Microgrid That Makes Optimum Use of City Gas as the Fuel and Mitigates Negative Effects of Intermittent Generators on Distribution Grid***

  The sequential steps discussed below were developed to optimize gas energy as a fuel while reducing the negative consequences of intermittent generators on the distribution grid.

  1. Generation scheduling is started automatically by the EMS.
  2. The EMS acquires weather information and past power demand records.
  3. The demand forecast is conducted by the EMS based on the weather forecast and past demand patterns and forecast values are acquired by the EMS from PV output forecasting unit.
  4. An optimum generation schedule is then prepared by the EMS for the next day at 30-minute intervals.
  5. EMS acquires PV output, output of fuel cells, power flow at the PCC, power of the battery, and battery SOC.
  6. The fuel cell is provided with a dispatch command by the EMS based on supply/demand imbalance and optimum generation scheduling.
  7. The battery is also provided with a power dispatch command by the EMS based on supply/demand imbalance and optimum generation scheduling.
  8. The EMS' dispatched power flow at the PCC is acquired by the battery controller.
  9. The power dispatch command is provided by battery controller so that the power flow at the PCC conforms to the dispatch value.

  The requirements include, the system shall:

  1. Provide updates of storage and renewable energy
  2. Receive and process output commands from the EMS
  3. Validate execution of output commands to the EMS.

Protection:

- ***Microgrid Functional Use Case #F-7:Microgrid Protection***

  The sequential steps were developed for microgrid protection.

  1. The area power system status and microgrid status are updated.
  2. Protection settings are determined and new protection settings are distributed and executed.
  3. The execution is confirmed and the protection status is updated.
  4. Fault conditions are identified and tripping signals are sent.

5. The tripping signal is executed to isolate faults and the protection controller is informed of the protection device status.
6. The microgrid SCADA is informed of the status and topology change and the area power system is informed of the microgrid status.

The requirements include, the system shall:

1. Update statuses of the microgrid to the EMS
2. Receive and update protection settings from the EMS
3. Distribute protection setting updates
4. Validate protection updates
5. Update the EMS with protection statuses.

Black Start:

- ***Microgrid Functional Use Case #F-9: Microgrid Protection***

The sequential steps were developed for microgrid protection from black start.

1. The microgrid switch status confirmation and the open command are sent.
2. The microgrid status is confirmed.
3. The black start request is sent and a response determined.
4. The black start procedure is then initiated and the black start initialization commands are sent and executed.
5. The initialization execution is confirmed and primary source and matching load 1 are started.
6. The primary source start is executed and the start of primary resource is confirmed.
7. The system starts other sources and loads according to the order in the pre-determined procedure
8. The start of other sources and loads is executed and then confirmed.
9. Islanded operation commences, dispatches and finally the status is sent.

The requirements include, the system shall:

1. Provide the status of the system
2. Process and validate commands received (open and black start)
3. Validate the execution of commands.

Voltage and Frequency Control:

- ***Microgrid Functional Use Case #F-1: Frequency Control***

  The sequential steps were developed for microgrid frequency control.

  1. Measurement are updated and the microgrid source control modes and frequency setting point in the control commands are updated.
  2. The control commands are sent and the microgrid frequency to primary sources are sent.
  3. The control commands are executed.

  The requirements include, the system shall:

  1. Provide statuses to the EMS
  2. Receive control commands related to control mode and frequency
  3. Process control commands
  4. Validate control command execution.

- ***Microgrid Functional Use Case #F-2: Voltage Control (Grid- connected and Islanding)***

  The sequential steps are similar to those discussed above and were developed for microgrid voltage control.

  1. The voltage/power factor profile is received.
  2. The measurements are updated and the microgrid source control modes and voltage/power factor setting point in the control commands is updated.
  3. The control commands are sent and the microgrid voltage/power factor to primary sources sent.
  4. The control commands are executed.

  The requirements include, the system shall:

  1. Provide statuses to the EMS
  2. Receive control commands related to control mode and frequency
  3. Process control commands
  4. Validate control command execution.

- ***Microgrid Interactive Use Cases #IA-8: Update Aggregated at PCC Real and Reactive Load-to-Frequency and Load-to-Voltage Dependencies in the Emergency Ranges***

  The sequential steps discussed below were developed for Real and Reactive Load-to-Frequency and Load-to-Voltage Dependencies in the Emergency Ranges.

  1. Dynamics of DMS frequency and PCC voltage during emergencies determined by DMS contingency analyses.
  2. Dependencies of the microgrid natural real and reactive load on frequency and voltage within the emergency ranges, including the conditions of stalled motors and disconnected loads.
  3. Dependencies of DER/ES real power generation on frequency and voltage within the emergency ranges, including the ride-through functions.
  4. Dependencies of microgrid reactive power generation/absorption on frequency and voltage within the emergency ranges, including the ride-through functions.
  5. Dependencies of the microgrid net real and reactive load on frequency and voltage within the emergency ranges (can be derived from the above information).
  6. Updates of the setups of the RAS and Ride-through functions based on the frequency and voltage dynamics provided by the DMS and/or based on specific DMS requests.
  7. Preventive measures requested by the DMS.
  8. Planned/expected preventive measures to be implemented by microgrid based on the DMS requests.
  9. Updates on changes during the abnormal conditions.
  10. Commands, requests, and instructions to the microgrid EMS issued by the DMS during the emergencies.
  11. Updates of the microgrid restorative state after the emergency (connection state, disconnected load and generation, ability for black start, desired sequence of restoration, etc.).
  12. Updates by the DMS on the conditions for restoration, such as the condition for re-synchronization, if the microgrid was disconnected, the conditions for restoration of loads, needs in black start, etc.
  13. The timing of the information exchange should be consistent with significant changes of the above-listed data. Many of the underlying operational condition for these data change in near-real time. Therefore, the updates of the data exchanges should be in the near-real timeframe, like on by exception basis.

14. Because of the step-wise nature of some of the above-mentioned components, the aggregated dependencies may be non-monotonous and piecewise. They may depend on more than one independent variable e.g., frequency and voltage changing concurrently. Hence, the structure of the exchanged data should support multi-dimensional, non-monotonous dependencies, command/request formats, and metrics of data uncertainty. The dependencies should cover practical emergency ranges of the independent variables.

The requirements include, the system shall:

1. Provide statuses to the EMS
2. Receive control commands related to restorative state (connection state, disconnected load and generation, ability for black start, desired sequence of restoration, etc.)
3. Process control command
4. Validate control command execution.

Additions to State/Status Monitoring:

- ***Microgrid Interactive Use Cases #IA-7: Updating Dependencies of the Microgrid Operational Model on External Conditions***

The sequential steps discussed below were developed to updated microgrid operational model dependencies with external conditions.

1. Dependencies of the microgrid natural real and reactive load on weather, dynamic prices, and DMS request for ancillary services.
2. Dependencies of real and reactive load-to-voltage sensitivities on weather, dynamic prices, and DMS request for ancillary services.
3. Dependencies of DER/ES real power generation on weather, dynamic prices, and DMS request for ancillary services.
4. Dependencies of microgrid reactive power generation/absorption on weather, dynamic prices, and DMS request for ancillary services.
5. Dependencies of the microgrid net real and reactive load on weather, dynamic prices, and DMS request for ancillary services (can be derived from the above information).
6. Dependencies of the microgrid reactive power nominal and operational capability on weather, dynamic prices, and DMS request for ancillary services.
7. Dependencies of the microgrid dispatchable real and reactive power on weather, dynamic prices, and DMS request for ancillary services.
8. Dependencies of the microgrid losses on weather, dynamic prices, and DMS request for ancillary services.
9. Dependencies of the load power factors of on weather, dynamic prices, and DMS request for ancillary services.

10. Dependencies of the setups of the RAS and ride-through functions on the weather, dynamic prices, and DMS request for ancillary services.
11. Preventive measures implemented by microgrid in response to warning about a VLSE.
12. Planned/expected measures to be implemented by microgrid during the VLSE.
13. Updates on changes during the disaster.
14. Dynamic prices from DMS.
15. Requests for ancillary services from DMS.
16. Weather conditions from weather sources.
17. Commands, requests, and instructions to the microgrid EMS issued by the DMS before and during the VLSE.
18. Updates of the microgrid restorative state after the VLSE.
19. The DMS updates the microgrid EMS on the conditions for restoration, such as the condition for resynchronization, if the microgrid was disconnected, the conditions for restoration of loads, etc.
20. The timing of the information exchange should be consistent with significant changes of the above-listed data. Many of the underlying operational condition for these data change in near-real time. Therefore, the updates of the data exchanges should be in the near-real timeframe.
21. The structure of the exchanged data should support multi-dimensional, non-monotonous dependencies, command/request formats, and metrics of data uncertainty. The dependencies should cover practical ranges of the independent variables.
22. The EMS/DMS applications will use these data in their "what-if" studies to derive the near-real time and short-term look ahead solutions.

The requirements include, the system shall:

1. Provide statuses to the EMS
2. Receive control commands related to preventative measures
3. Process control commands
4. Validate control command execution.

3.6 Information Exchanged for Each Function

The table below provides a list of information exchanged for a selection of use cases that are examined throughout this document deemed to be the most architecturally significant. The information is noted by use case rather than by function.

Table 3-10
Function Information Exchanged

Information Exchanged	Use Case
1. Measurements and status – Includes voltage, current and/or power measured at each actor, and the status of the actor, including on/off status, operation modes, and other actor operation status indicators. 2. Microgrid control commands – The control commands sent from microgrid SCADA to individual microgrid actors, including sources, loads, microgrid switch, and protection devices. The commands dispatch the economic dispatch from the microgrid EMS, and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point. 3. Microgrid frequency measurement – The frequency of the microgrid is measured at PCC and distributed to the primary source for frequency control and resynchronization purposes.	*Microgrid Functional Use Case #F-1* *Frequency Control*
1. Measurements and status – Includes voltage, current and/or power measured at each actor, and the status of the actor, including on/off status, operation modes, and other actor operation status indicators. 4. Microgrid voltage/power factor profile – The command from the area electric power system. It can be voltage or power factor profile at PCC that the area electric power system requires the microgrid to maintain if the microgrid participates in the real-time operation of the area electric power system operation. 3. Microgrid control commands – The control commands sent from microgrid SCADA to individual microgrid actors, including sources, loads, microgrid switch, and protection devices. The commands dispatch the economic dispatch from the microgrid EMS, and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point. 4. Microgrid voltage/power factor at PCC – Microgrid voltage/power factor measurement at PCC.	*Microgrid Functional Use Case #F-2* *Voltage Control (Grid-connected and Islanding)*

Table 3-10 (continued)
Function Information Exchanged

Information Exchanged	Use Case
1. Microgrid bid – The microgrid's bid for energy and/or ancillary services sent from the microgrid EMS to the market operator. It also contains information of the microgrid's availability to participate in the energy market when the microgrid is in different operation conditions. 2. Market dispatch – The dispatch from the market operator to the microgrid EMS. The microgrid incorporates this dispatch information into its optimization. 3. Microgrid economic dispatch – The dispatch signal sent from microgrid EMS to microgrid SCADA. It incorporates both the microgrid operation conditions and the market dispatch when the microgrid is available to participate in the energy market, or only considers the microgrid itself when it is unavailable to do so. 4. Measurements and status – Includes voltage, current and/or power measured at each actor, and the status of the actor, including on/off status, operation modes, and other actor operation status indicators. 5. Microgrid control commands – The control commands sent from microgrid SCADA to individual microgrid actors, including sources, loads, microgrid switch, and protection devices. The commands dispatch the economic dispatch from the microgrid EMS, and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point. 6. Islanding request – A signal sent from microgrid SCADA to area power system requesting permission for intentional islanding 7. Islanding request response – The response of area power system to the islanding request. It can be yes (allow intentional islanding) or no (not allow). 8. Islanding commands – The commands sent by microgrid SCADA to microgrid actors to control the microgrid so that the power flow is minimized to specified ranges at the microgrid switch for intentional islanding transition. 9. Islanding commands response – After the actors have executed the islanding commands, the confirmation signal sent to the microgrid SCADA to indicate that intentional islanding conditions have been met. 10. Microgrid switch open command – A command sent by microgrid SCADA to microgrid switch to open the switch so that the microgrid is disconnected from area power system. 11. Microgrid switch status – A signal sent by microgrid switch indicating the status of the microgrid switch.	*Microgrid Functional Use Case #F-3* *Grid Connected to Islanding Transition – Intentional*

Table 3-10 (continued)
Function Information Exchanged

Information Exchanged	**Use Case**
1. Measurements and status – Includes voltage, current and/or power measured at each actor, and the status of the actor, including on/off status, operation modes, and other actor operation status indicators. 2. Microgrid control commands – The control commands sent from microgrid SCADA to individual microgrid actors, including sources, loads, microgrid switch, and protection devices. The commands dispatch the economic dispatch from the microgrid EMS, and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point. 3. Microgrid switch status – A signal sent by microgrid switch indicating the status of the microgrid switch. 4. Microgrid status – Information sent by microgrid SCADA to area power system indicating the operation status of the microgrid.	*Microgrid Functional Use Case #F-4* *Unintentional Islanding to Grid-Connected Transition*
1. Microgrid bid – The microgrid's bid for energy and/or ancillary services sent from the microgrid EMS to the market operator. It also contains information of the microgrid's availability to participate in the energy market when the microgrid is in different operation conditions. 2. Market dispatch – The dispatch from the market operator to the microgrid EMS. The microgrid incorporates this dispatch information into its optimization. 3. Microgrid economic dispatch – The dispatch signal sent from microgrid EMS to microgrid SCADA. It incorporates both the microgrid operation conditions and the market dispatch when the microgrid is available to participate in the energy market, or only considers the microgrid itself when it is unavailable to do so. 4. Measurements and status – Includes voltage, current and/or power measured at each actor, and the status of the actor, including on/off status, operation modes, and other actor operation status indicators. 5. Microgrid control commands – The control commands sent from microgrid SCADA to individual microgrid actors, including sources, loads, microgrid switch, and protection devices. The commands dispatch the economic dispatch from the microgrid EMS, and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point.	*Microgrid Functional Use Case #F-5* *Islanding to Grid-Connected Transition*

Table 3-10 (continued)
Function Information Exchanged

Information Exchanged	Use Case
6. APS status – Microgrid switch detects that area power system is in normal operation and sends a signal to microgrid SCADA indicating the status. 7. Re-connection request – A signal sent by microgrid SCADA to area power system to request permission for reconnection. 8. Re-connection request response – Response from area power system to microgrid SCADA if reconnection is allowed or not. 9. Re-synchronization dispatch commands – The commands sent by microgrid SCADA to microgrid actors to control the microgrid so that the microgrid voltage magnitude, frequency, and phase angle at PCC match the voltage on the grid side within specified ranges. 10. Microgrid switch status – A signal sent by microgrid switch indicating the status of the microgrid switch.	*Microgrid Functional Use Case #F-5 Islanding to Grid-Connected Transition*
1. Microgrid bid – The microgrid's bid for energy and/or ancillary services sent from the microgrid EMS to the market operator. It also contains information of the microgrid's availability to participate in the energy market when the microgrid is in different operation conditions. 2. Market unit commitment 3. Microgrid economic dispatch – The dispatch signal sent from microgrid EMS to microgrid SCADA. It incorporates both the microgrid operation conditions and the market dispatch when the microgrid is available to participate in the energy market, or only considers the microgrid itself when it is unavailable to do so. 4. Measurements and status – Includes voltage, current and/or power measured at each actor, and the status of the actor, including on/off status, operation modes, and other actor operation status indicators. 5. Microgrid control commands – The control commands sent from microgrid SCADA to individual microgrid actors, including sources, loads, microgrid switch, and protection devices. The commands dispatch the economic dispatch from the microgrid EMS, and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point. 6. Microgrid switch status – A signal sent by microgrid switch indicating the status of the microgrid switch. 7. Day-ahead demand forecast 8. Day-ahead renewable output forecast 9. Short-term demand forecast 10. Short-term renewable forecast 11. Real-time demand 12. Real-time renewable output	*Microgrid Functional Use Case #F-6 Energy Management (Grid-Connected and Islanding)*

Table 3-10 (continued)
Function Information Exchanged

Information Exchanged	Use Case
1. APS status – Microgrid switch detects that area power system is in normal operation and sends a signal to microgrid SCADA indicating the status. 2. Microgrid status – Information sent by microgrid SCADA to area power system indicating the operation status of the microgrid. 3. Protection settings – Protection device settings sent by protection controller to protection devices based on the present operation conditions. 4. Protection setting execution confirmation – The signal sent by protection relays to protection controller after the protection settings are implemented in the protection devices. 5. Protection system status – Signal sent by protection controller to microgrid SCADA indicating the present protection settings and status. 6. Tripping signal – After a fault occurs, protection devices detect and determine if the protection device needs to be tripped to isolate the fault. The tripping signal is generated by the protection device logic and sent to the fault current interruption device (switchgear). 7. Microgrid status and topology information – After	*Microgrid Functional Use Case #F-7 Microgrid Protection*
1. Microgrid day-ahead bids for ancillary services 2. Microgrid hour-ahead bids for ancillary services 3. Market dispatch 4. Microgrid economic dispatch – The dispatch signal sent from microgrid EMS to microgrid SCADA. It incorporates both the microgrid operation conditions and the market dispatch when the microgrid is available to participate in the energy market, or only considers the microgrid itself when it is unavailable to do so. 5. Measurements and status – Includes voltage, current and/or power measured at each actor, and the status of the actor, including on/off status, operation modes, and other actor operation status indicators. 6. Microgrid control commands – The control commands sent from microgrid SCADA to individual microgrid actors, including sources, loads, microgrid switch, and protection devices. The commands dispatch the economic dispatch from the microgrid EMS, and send control signals to the actors between the two economic dispatches to maintain the system stability during islanded operation mode. The commands include the microgrid source control mode commands, real and reactive power dispatch commands, and load levels for controllable loads. The source control mode commands determine if a microgrid source is operated as a primary source that controls the frequency and/or voltage of the microgrid during islanded operation condition or as other source. It also includes the frequency and voltage setting point. 7. Day-ahead demand forecast 8. Day-ahead renewable output forecast 9. Short-term demand forecast 10. Short-term renewable forecast 11. Ancillary service contracts	*Microgrid Functional Use Case #F-8 Ancillary Services (Grid-Connected)*

Table 3-10 (continued)
Function Information Exchanged

Information Exchanged	Use Case
1. APS status – Microgrid switch detects that area power system is in normal operation and sends a signal to microgrid SCADA indicating the status. 2. Microgrid status – Information sent by microgrid SCADA to area power system indicating the operation status of the microgrid. 3. Microgrid switch open command – A signal sent by microgrid SCADA to microgrid switch to open the microgrid switch before the black start starts. It ensures that the microgrid is disconnected from any other external circuit. 4. Microgrid switch status – A signal sent by microgrid switch indicating the status of the microgrid switch. 5. Black start request – A signal sent from microgrid SCADA to area power system requesting permission for black start. 6. Response to black start request – The response of area power system to the black start request. It can be yes (allow black start) or no (not allow). 7. Black start initialization commands – Commands 8. Confirmation of black start initialization – A signal sent by microgrid actors to microgrid SCADA indicating that the initialization is completed. 9. Start primary resource command – A signal sent by microgrid SCADA to primary source to start energizing the microgrid by starting the primary source with proper load levels. 10. Confirmation of primary resource start – A signal sent by primary source to microgrid SCADA indicating that the primary source is started and a microgrid is formed. 11. Start other sources and loads commands – Following pre-determined procedures, microgrid SCADA send operation signals to other sources and loads to restore the operation of the entire microgrid. 12. Confirmation of the start of other sources and loads – A signal sent by each source or load to microgrid SCADA indicating the start of the actor. 13. Islanded operation dispatch – Dispatch commands sent by microgrid EMS to microgrid SCADA for economic dispatch in islanded mode. 14. Islanded operation status – Information on microgrid islanded operation sent by microgrid SCADA to area power system.	*Microgrid Functional Use Case #F-9* *Microgrid Protection*

Table 3-10 (continued)
Function Information Exchanged

Information Exchanged	**Use Case**
1. APS status – Microgrid switch detects that area power system is in normal operation and sends a signal to microgrid SCADA indicating the status. 2. Microgrid status – Information sent by microgrid SCADA to area power system indicating the operation status of the microgrid. 3. Microgrid switch open command – A signal sent by microgrid SCADA to microgrid switch to open the microgrid switch before the black start starts. It ensures that the microgrid is disconnected from any other external circuit. 4. Microgrid switch status – A signal sent by microgrid switch indicating the status of the microgrid switch. 5. Black start request – A signal sent from microgrid SCADA to area power system requesting permission for black start. 6. Response to black start request – The response of area power system to the black start request. It can be yes (allow black start) or no (not allow). 7. Real-time microgrid data – The data for microgrid real-time control and energy management. It includes the data measured and calculated by microgrid actors, and the data calculated by microgrid SCADA and microgrid EMS. 8. Real-time area power system operation data – The data of area power system operations that are sent to microgrid controller for microgrid real-time control. 9. Real-time operation data – The data from energy market sent to microgrid controller for microgrid energy management. 10. Non-real-time microgrid data – The data that are archived to record microgrid operations. 11. Real-time microgrid control signals – The control signals sent by microgrid controller, either autonomously or by the microgrid operator, to other actors in the microgrid to perform certain functions.	*Microgrid Functional Use Case #F-10* *Microgrid User Interface and Data Management*

Section 4: DMS Integration With Microgrid Controller/DERMS

In a distribution grid, the DMS is responsible for activities related to operations and a microgrid controller is responsible for its own internal grid. The following EPRI reports provides detailed information on the DMS functionalities, applications and architectures. These reports explain how electric utilities can successfully plan, implement and use DMS effectively to accomplish the desired objectives. This report provides a roadmap that electric distribution utilities can use as a guide in performing key DMS implementation activities starting with project inception to DMS contract award. One of the key shortcoming of these reports is that it does not provide information on how DMS system and Microgrid controllers can be mapped together, what are the operation rules for both DMS and the microgrid controller and what functions and messages will need to be shared between the two systems.

These 6 documents are the seminal research related to DMS. All subsequent work is based on this. This section relies on the following documents:

1. *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385
2. *Integrating Smart Distributed Energy Resources with Distribution Management Systems* EPRI, Palo Alto, CA: 2012 1024360
3. *Smart Distribution Applications for Distributed Energy Resources: Distribution Management*
4. *System Use Cases.* EPRI, Palo Alto, CA: 2013. 3002002464
5. *Program on Technology Innovation: Seamless Energy Management System Part I: Assessment of Energy Management Systems and Key Technological Requirements.* EPRI, Palo Alto, CA: 2014 3002004092
6. *2012 Grid Strategy: Distribution Management System (DMS) Advanced Applications for Distributed Energy Resources.* EPRI, Palo Alto, CA: 2012.1025572

Both microgrids and DMS are responsible for the operation of the point of coupling (POC) when the microgrid is in grid tied mode and the transitions between modes. The responsibilities for the operation of the POC include:

- Maintaining desired voltage profiles
- Constant power exchange
- Intentional disconnection and re-connection
- Mutual emergency support
- Protection coordination[82]

Because microgrid controllers are such versatile systems, they may be implemented as an independent entity located in a local or remote area or they can be tied directly to the DMS, either as an application or as a physical part. The integration of the DMS and a microgrid controller may be different during actual implementation because of their physical locations and specific implementation approaches. The basic principles and strategies would generally apply for integration of the two entities as long as they are classified as standard microgrids following industry standards as defined in IEEE 1547.[83]

A DERMS is intended to manage and control individual DERs through the accumulation of isolated DERs associated with a DERMS throughout the distribution grid. It is possible for the grid may have multiple DERMS covering the entire territory of one DMS, with each DERMS being responsible for a portion of the distribution grid. A DERMS may be implemented in local or remote areas in that same way that a microgrid controller can. A DERMS may also operate as a sub-function or application of a DMS. While there may be differences in the physical location and manner of actual implementations, there should not be different overall principles or strategies in the implementation of these systems.[84]

4.1 Relationship between DMS, DERMS and Microgrid Controllers

The DMS generally adopts the leading role while the microgrid controller and DERMS are responsible for supporting positions during the integration of all three system; however, each of the systems maintains its own responsibilities, functions, and tasks. DMS is a tool to aid distribution system operators as well as engineers, technicians, and managers for capabilities that include analysis,

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[82] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[83] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[84] Ibid.

troubleshooting, maintenances, and decision making support.[85] The functions of a microgrid controller may be executed in a physically independent device or a processor located within the vicinity of the microgrid. Additionally, the functions of a microgrid controller may also be implemented as a subsystem or a sub-function of the DMS or a different system altogether that operates in parallel to the DMS.[86]

Regardless of the specifics of how and where a microgrid controller is implemented, its functionality should derive from independent logic. Along the same lines, the integration of the DMS with a DERMS may be completed in a variety of ways. A DERMS may be entirely independent of the DMS and may be located remotely or virtually in the case of third-party DERMS. As discussed above, a DERMS may also be implemented as a sub-function or a designated application of the DMS. Again, regardless of what the specifics of implementation are, the central functionality of DERMS and the integration logic with the DMS should be comparable. There are situations where a microgrid is directly managed by DERMS instead of communicating directly to the DMS. In these scenarios, the microgrid may be treated the same as the other DERs by the DMS and responsibilities as a microgrid to DMS integration would be disregarded. In these cases, the microgrid operation is modeled and managed as an aggregated DER during grid tied mode.[87]

4.2 DMS Applications

An effective DMS is intended to integrate with existing utility systems to optimize the performance of each system respectively. Systems that DMS integration is geared towards include:

- Customer Information System (CIS)
- Geographic Information System (GIS)
- Outage Management System (OMS)
- Energy Management System (EMS)
- Other information and control systems

The optimization efforts from the DMS aim to improve efficiency, reliability, visibility, control, support analytics, and overall decision-making for the utility as a whole. An effective DMS can optimize the monitoring and control processes of distribution systems, which is important to maximize the utilization of past, ongoing, and future smart grid investments and further expand the value of associated assets. With the ever increasing proliferation of DERs in a distribution

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[85] *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385.

[86] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids.* Argonne National Laboratory, Argonne, IL: 2015.

[87] Ibid.

grid, a DERMS may be necessary for the overall management of operations of available DERs.[88]

A DMS is a support system designed to assist with decision-making processes and distribution system optimization by integrating external applications at the enterprise level. DMS is a useful tool for enhancing DER penetration through inverter integration and is used for other applications like Volt-VAR optimizations and communication system implementation. While external systems like AMI are able to integrate with a DMS, they do not affect the functionality of the DMS with respect to distribution grid operations.[89] This means that like a microgrid, a DMS can integrate with multiple DERMS, both internal and external to the utility.

In addition to supporting subsystems that provide overall system models and real-time data acquisition, a DMS also includes many advanced applications for various functionalities. As is discussed in Section 2.1.2.2, DMS includes the following functions:

- Data acquisition (substation SCADA RTUs, SCADA facilities associated with field devices, AMI meters)
- Data processing (alarm limit checking, reasonability limit checking, data quality processing, normal/off normal processing, alarm detection, sequence of events processing, momentary change direction)
- DMS control outputs
- Geographical User Interface (GUI)
- Intelligent alarm processing
- Historical information systems
- Distribution application functions
- Distribution system model
- Topology processor
- On-line power flow
- Short circuit analysis
- Switch order management
- Volt-VAR optimization
- Fault location, isolation, and service restoration
- Optimal network reconfiguration

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[88] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[89] *Integrating Smart Distributed Energy Resources with Distribution Management Systems* EPRI, Palo Alto, CA: 2012 1024360.

- Short term load forecasting
- Dispatcher trainer simulator
- Dynamic equipment rating
- DMS control of protection settings (fuse saving enable/disable, cold load pickup enable/disable)
- DER monitoring and control
- Emergency load shedding
- Integration with eternal systems (GIS, AMI, OMS, EMS, corporate data historian).[90]

The applications listed above are the primary advanced functions in a DMS and are designed to control and manage distribution grids with passive networks. All of the applications face challenges associated with the increasing propagation of DERs that cause for highly active distribution grids.[91]

4.3 DMS Current Status

The implementation status of DMS varies from utility to utility. While some are deep into the process of implementing DMS, others are just starting the planning phase n. Because DMS is such a versatile and robust system, there are also varying degrees of utilization amongst DMS applications. Fault location isolation and service restoration (self-healing), Volt/VAR optimization, online power flow, and switch order management are all DMS applications that have gained wide popularity and consensus among users. Other emerging applications such as DER management are consistent with the industry trend of increased installation of DERs and microgrids. It is widely agreed that many issues related to DMS implementation including business case development, cost/benefit analysis, project planning/design and specifications, system integration, measurement and verification need further research and development.[92]

Most currently operating DMS are intended to achieve automation and management operational requirements of conventional distribution grids. Traditional distribution grids generally include common features that pertain to passive networks that are frequently designed for distribution feeders in a radial operation topology configuration. As discussed in Section 4.2, a standard DMS is tied directly to several subsystems and major software modules. These systems may include but are not limited to a Data & Model Management (DMM)

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[90] *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385.

[91] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[92] Ibid.

module, a combination of advanced applications, a User Interface (UI) module, SCADA, and GIS.[93]

4.4 Operations of DMS and Microgrid Controllers

Microgrids operate in either grid tied mode (connected to the distribution grid) or islanded mode (separated either intentionally or unintentionally from the distribution grid). The integration of a DMS and microgrid controller(s) must ensure that both the distribution grid and the microgrids are making smooth transitions between grid-tied and islanded mode as well as maintaining reliability for standard operations and emergency conditions. A microgrid should meet specific operation requirements in either grid tied or islanded mode that include:

- Maintaining an acceptable voltage profile
- Grid frequency
- Synchronization
- Load following.

A microgrid is a useful tool to provide support during atypical conditions in grid tied mode. Additionally, a microgrid can follow a predetermined schedule for standard operations between the DMS and microgrid to exchange energy with a relevant utility during grid tied mode. In islanded mode a microgrid is expected to stabilize its internal load demand with its available energy resources while sustaining the same level of grid frequency and voltage quality. A microgrid should also be able to reconnect to the distribution grid when instructed.[94]

The installation of a DERMS can support DMS operations by significantly reducing the uncertainties that result from DERs that may not perform based on a coordinated operation pattern. With the integration of a DERMS, the DMS is able to receive real-time generation values of grouped DER units (DER group) along with their operation schedules for look-ahead time intervals. The support of an integrated DERMS can also play an effective role in enhancing operational reliability because it has the capability to allow the DMS to make decisions regarding predictive operations, control, and management.[95]

The responsibilities of a microgrid controller include the operation and management of microgrid generation resources and loads as well as transitions between grid-tied and islanded mode to the distribution grid. Management of the microgrid includes sustaining constant real and reactive power exchanges in addition to healthy voltage profiles during grid tied mode. Microgrids are

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[93] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[94] Ibid.

[95] Ibid.

designed to automatically disconnect from the distribution grid when necessary.[96] The DMS provides information to microgrids for operational direction, including information related to voltage ranges and power exchange fluctuation tolerances. The DMS also is also able to prompt emergency requests with detailed emergency support requirements to microgrids.[97]

The DERMS is responsible for direct management of individual DER including feeder power flow management and voltage at the PCC. By integrating applicable DER the DERMS is able to coordinate individual assets into one entity that can dispatch or consume as directed.[98] DERMS are able to manage DER in an increasingly sophisticated manner through DER grouping based on: physical location, energy sources, maximum and available real and reactive capacities, availability based on time, and volt/VAR and frequency information. The grouping feature also will account for any future needs whether they are of statutory, regulatory, or operationally based. The DERMS is also responsible for simplifying and aggregating information such that the DMS is able to utilize it. During emergency operations, the DERMS is responsible for responding to emergency requests received from the DMS.[99]

4.5 DMS Design Principles for Microgrid Controllers/DERMS Integration

As discussed above, DERMS is essentially responsible for managing, controlling, and organizing DERs in a distribution system that has the capability of being controlled and managed by a DMS. As such, the DERMS must be properly integrated with the DMS otherwise it will not be able to perform its applications by providing available data in both systems. This setup creates the foundation for both systems to work in a synchronized way, operating and managing the appropriate applications of the distribution system. A distribution grid may have multiple DERMS (inside and outside the utility) with each DERMS being responsible for the DERs in its respective portion of the distribution grid.[100]

A conventional DMS is usually designed for passive distribution networks. In a passive distribution network the energy sources are the primary buses of distribution substation transformers[101]. The power flows operate in one direction through the distribution circuits (generally in a radial configuration) from the

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[96] *Smart Distribution Applications for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2013. 070625.

[97] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[98] *Smart Distribution Applications for Distributed Energy Resources*. EPRI, Palo Alto, CA: 2013. 070625.

[99] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[100] Ibid.

[101] Ibid.

sources to the end consumers. However, with the ever increasing proliferation of DERs and microgrids, the distribution networks are experiencing an increasing number of DER and microgrid connections. DERs and microgrids have their own operation and management systems (DERMS for DERs and microgrid controllers for individual microgrids). The challenges for the DMS stem from interacting with the active distribution networks as well as integration with DERMS and the microgrid controllers. These challenges require a continuously improving set of design principles and guidelines for the development of a new generation of DMS. A DMS that is constantly being improved upon allows for the optimization of effective control and management of the active distribution systems and unified integration between both DERMS and microgrids.[102]

4.6 Communication Requirements between DMS and Microgrid Controllers

A microgrid should have access to the necessary data communication information for operation management activities during standard operations and also during emergency conditions while connected to the distribution grid. During standard operation conditions, the DMS needs to be able to receive the following information:

- Energy interchange and voltage/VAR support schedules between the microgrid and the distribution grid at the Point of Common Coupling (PCC)
- Real-time data in terms of phase voltages, currents, kWs and kVARs at the active POCs.
- Simplified internal operation topology from the microgrid to indicate if it forms wheeling paths (which may cause hidden loops and lead to operations challenges or worse) to the distribution grid in case that multiple POCs are in active status.

During emergency conditions (prompted from a microgrid or from the distribution grid in grid tied mode) assistance may be required from the other system which did not initiate the emergency conditions status. Support includes emergency energy interchange and voltage/VAR support. The request for emergency assistance should be advanced to the non-initiating party and be verified immediately in an effort to effectively mitigate the emergency situation. During severe fault conditions the POCs should be disconnected by the relay protections (unintentional disconnection).[103]

In the case of an unintentional disconnection, both the DMS and the microgrid controller should quickly isolate the problem and subsequently proceed with measures to restore load balancing and voltage profile recovery. In the case of an

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[102] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[103] Ibid.

intentional disconnection, either initiated by the microgrid controller or the DMS, depending upon which entity instigates the disconnection, the other system should be notified to prepare for the disconnection. This preparation includes re-optimizing the grid voltage profiles and reducing the energy interchange to be near zero at the POCs by equalizing real and reactive demands in their respective distribution grids. The microgrid should notify the DMS for reconnection to the grid as there may be circumstances where the microgrid requires a confirmation notice before commencing the reconnection process. Once confirmation is received (if necessary), the microgrid can begin the resynchronization process. This process requires that the grid frequency and voltage match the distribution grid values closely across the POC. Additionally, the voltage angle difference between the two distribution grids at the POC is close to zero. The energy exchange and support functions can be initiated once the system is connected and stabilized.[104]

The DERMS may consider the distribution network topology in its operation model while grouping DER to optimize operations schedules. The schedules developed by the DERMS are separated to the individual DER as a base operations setting. The DER group schedules are relayed to the DMS in various groupings depending on DER modeling within the DMS. The schedules will be finalized and committed after being reviewed and validated and potentially adjusted if need be. Once the schedules are committed, they can undergo additional revisions or cancelation should operations conditions change or if emergency conditions are encountered. The DERMS may directly manage and control a DER or alternatively relay the DER's set points and operation schedules to the DMS if the DMS is the managing entity. In both scenarios, the DMS should also monitor the grouped DER operations, much like DERMS. Ideally both the DERMS and the DMS would share real-time information from the DER, regardless of actual system data collection and ownership responsibilities.[105]

4.7 Data Exchanges between DMS and Microgrid Controllers

The communication integration of the DMS with microgrids and DERMS can be implemented in many ways. The data exchange requirements for integration of the DMS with microgrids include the following:[106]

- **Connection Status**: The DMS and microgrid should both know the connection status at each POC.
- **Voltages**: The DMS and the microgrid controller should both know the intentional and actual voltages at each active POC when the microgrid is in

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[104] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[105] Ibid.

[106] Ibid.

grid tied mode. If the microgrid is disconnected, it may need to know the voltages at both sides of a POC if there is an intention to reconnect.

- **Power Exchanges**: The DMS and the microgrid controller should both know the actual real and reactive power exchanges at each active POC. They should both also know the net target power exchanges between the two systems. Both systems should be notified if any significant unintentional wheeling exists. In the case that wheeling does exist, the microgrid should take necessary precautions to prevent it from continuing.
- **System Frequency**: If the microgrid is in the disconnected mode and has an intention to reconnect to the grid, it should monitor the distribution grid frequency and once it is re-connected, the system frequency should be balanced on both sides.
- **Power Exchange Schedules**: The power exchanges between the distribution grid and the microgrid may be pre-scheduled to optimize sharing amongst available energy resources. Both parties may negotiate tentative schedules back and forth before the finalization of a formal version for commitment. Once committed, both parties should follow the schedule as closely as possible. Adherence of the schedule may be the responsibility of the microgrid which can control its energy resources to balance internal demands and exchanges through the POCs. During emergency conditions, the committed schedules may be cancelled or terminated any time and new emergency schedules may be added if necessary.
- **Simplified Operation Topology of Microgrid**: The microgrid should provide a condensed operation topology to the DMS when more than one POC is activated. The condensed operation topology will benefit the system through its ability to monitor possible loops formed by the POCs as well as provide notifications of possible wheeling.
- **Connection/Disconnection Requests**: The microgrid may solicit consent from the DMS to connect or disconnect (intentional disconnection) to/from the distribution grid. The DMS has the ability to allow or refuse the connection request and also allow a disconnection request right away or ask for a short time delay. Alternatively, the DMS may also request the microgrid to connect or disconnect to/from the distribution grid. The microgrid may allow or refuse the connection request and ask for a time delay for a disconnection request. Under emergency conditions either system can instigate the process of disconnection without the need to gain approval.

4.8 Microgrid Controller Controls While Integrated with DMS

A microgrid's energy resources and load management applications should have adequate monitoring and control ability to support the synchronization with the distribution grid, support a desirable voltage profile at the POCs and its internal grid, and respond rapidly to the changes in internal load and generation and the disturbances from the distribution grid or the internal grid. The microgrid's operation conditions at the POCs should be monitored or available to the DMS.

The connection switch at the POCs can also potentially be operated by the DMS for emergent disconnection.[107]

4.9 DMS Function Enhancements with Microgrid Integration

A microgrid qualifies as an energy resource similar to a DER. In some situations a microgrid is considered a controllable load to the distribution grid and as such should be modeled appropriately in the DMS with variable generation and load capacities. Microgrid connections are useful for improving operational reliability and power supply quality of the distribution grid through potential optimization. Operation strategies in the DMS can be corrected to realize the operation rules and the innate qualities of microgrids, including those for power transactions, voltage/VAR optimization, emergency support, etc.[108]

4.10 Market and Energy Transactions for DMS and Microgrid Controllers

Both the DMS and the microgrid and should closely oversee power exchanges and/or energy transactions between the distribution grid and a microgrid. These interactions should also be controlled directly by the microgrid to adhere to established transaction schedules. The energy transactions that take place between the distribution grid and a microgrid are counted as net quantities from all active POCs of the microgrid.[109] Energy wheeling is likely to occur when multiple active POCs are involved. For instance, energy wheeling includes circumstances where one system delivers power to another system through one POC and receives power from another POC. This wheeling may need to be avoided during normal operations but may be needed in emergency support and as such should be well coordinated between the two systems. During emergency circumstances, wheeling can potentially provide alternative routes for power delivery and can also be useful for sustaining voltage profiles for the grid.[110]

4.11 Resource Optimization Requirements for DMS and Microgrid Controllers

The DERMS should take into account the network constraints of distribution grid operations during DER operation schedules optimization based on the availability of energy for the DER and the mandates at different levels. DERMS should communicate with the DMS in order to procure real-time operation conditions and established operation plans that are especially important because they identify network constraints. Prior to establishing a schedule, the DMS

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[107] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[108] Ibid.

[109] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[110] Ibid.

should verify that the schedule will not be the source of potential negative impacts to the reliability and service quality to the overall grid operation. As a result, the DMS has the option to accept or reject the proposed schedule or alternatively provide a better schedule for DERMS to consider. Once a schedule is deemed acceptable by both parties, it becomes a committed schedule that both systems will adhere to. During emergency conditions, temporary schedules may be utilized. An alternate option includes the DMS taking emergency actions via load shedding and/or the generation of some DERs.[111]

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[111] Ibid.

Section 5: Technical Gaps of Integrating DMS, DERMS, and Microgrid Controller

When a microgrid is connected to the distribution grid, it will have to adhere to the operation rules of the distribution grid at the POCs. This includes those operation rules that pertain to the DMS for the operation and control of the distribution grid. While the DMS may not control the operations of a microgrid, it should uphold guidelines to ensure that the microgrid will not cause operational complications to the distribution grid because of internal shortcomings such as incorrect topology configuration, circuit faults, voltage control, or load following related issues.

The microgrid should adopt islanded mode if an internal fault or event occurs that will compromise the operations of the distribution grid. The protection schemes in the DMS will operate if a fault occurs in the distribution grid. However, the related microgrids are also responsible for self-protection from any damage the fault may cause. The microgrid should be a part of the effort to uphold healthy voltage profiles of the distribution grid at the active POCs when it is in grid tied mode. Microgrids in grid tied mode should switch to islanded mode if a fault within the associated distribution circuit causes the circuit to become de-energized. The microgrids should also have the ability to ride through levels of low voltage that result from temporary fault conditions during a fault time period that is not the source of the circuit trip.[112]

Effective monitoring and control of DER operations may require two-way communications capabilities. Multiple communications and networking technologies are viability to support these applications, including traditional twisted-copper phone lines, cable lines, fiber optic cable, wireless cellular, satellite, power line carrier, and wireless short-range networks such as Wi-Fi and Wireless Mesh networks[113]. Proper communications technologies for DER monitoring and control is determined based on an analysis for a specific system's communications requirements. Communications technology needs mainly

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[113] Ibid.

depend on the type of applications, locations, and topologies of the system and also must be designed well.[114]

Bandwidth requirements for a communications network are derived on data traffic speed needs (how many data packets per second are needed) as well as data traffic patterns (the periodicity or burst for each application). Further, the bandwidth requirements of communications systems for DMS integration with DERs and microgrids depends on the control architecture and the applications that are intended to be supported. As one may expect, supporting more applications requires more bandwidth. According to the U.S. Department of Energy (DOE) guide on the bandwidth requirements, DER monitoring and control requirements lie between 9.6 kbps to 56 kbps. This DOE guide defines an acceptable range which should be considered during the design process based on and constraints for DER integration as well as specific application needs and requirements.[115]

Quality of service (QoS) requirements may be different in terms of data quality and communications latency due to various aspects of DER connections such as protection, monitoring and control, energy management, and post-event analysis. According to the DOE guide, a communications latency range required by DER connections should be between 20ms and 15s. Data quality can be increased through error correction and acknowledgement feedback mechanisms for data transmission. The communications latency can be improved by increasing the data transmission priority. The communications protocols utilized by the systems should enable adjustments for accuracy and latency of data transmission, specifically to accommodate the various QoS requirements for DER connections.[116]

Despite the prominence of DMS across utilities, it still lacks a standardized definition of what the scope of a DMS should entail, as well, a lack of formally agreed upon components and implementations. Often a utility's DMS is merely a combination of legacy systems. These piecemeal DMS usually involve a distribution SCADA system as a foundation that has then been "enhanced" through the addition of features, components, and applications that attempt to create a system that resembles an operation with DMS functionality. While an effective DMS should be built on the foundation of a SCADA system, it will only operate as effectively as the design of the SCADA system on which the DMS is built. When more features and applications are added to a system that often lacks a solid initial design, it should be no surprise that the end result resembles patches attached to a SCADA system. Because the design of this fragmented system is usually lacking, it will reach its performance and/or capability limit faster. Adding more applications and features, like connectivity with one or groups of microgrid systems, typically results in an end product that

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[114] Ibid.

[115] *Guidelines for Implementing Advanced Distribution Management Systems: Requirements for DMS Integration with DERMS and Microgrids*. Argonne National Laboratory, Argonne, IL: 2015.

[116] Ibid.

is costly to transform into a well-designed DMS compared to the cost of completely replacing it with a new system.[117]

Advanced DMS (ADMS) holds possibilities for utilities who are demanding higher reliability, improved power quality, renewable energy sources, and data security.[118] The (ADMS) contains the features and advanced applications of a DMS and is also integrated with other systems including OMS, AMI, and Demand Response Management (DRM). The operational characteristics of a DER in terms of operations in grid tied or islanded mode could affects the quality of power delivery and overall reliability of the distribution grid. This combination of factors result in significant challenges to DMS. These challenges include the ability to properly model the DER in the DMS as well as impacts related to microgrid controller, DERMS, and overall integration.[119] At the present time, only the most visionary and forward thinking utilities are aligned with the idea that ADMS provides a solution to the challenges they are experiencing, as well as a solution to mitigate future operational risks. Also, very little focus has been given to incorporate the microgrid applications with DMS

Currently, the available ADMS products are at the same level of sophistication as a Distribution SCADA. The software is immature, the capability of advanced analytics is lacking, and implementation is expensive. Also, extensive verifications and validations are needed before a specific applications like microgrids are implemented within ADMS and integrated within utility's distribution operations. As such, utilities have not yet seen an adoption rate of ADMS products that make them common place and a critical part of utility processes. Until utilities approach ADMS as a vital and imperative system in which day-to-day activities are reliant, the prevalence of ADMS in the field will continue to remain limited. Generally, utilities that favor ADMS have already completed its implementation, and those who have not will continue to wait until the product matures sufficiently to overcome its current shortcomings.

At the present time EPRI is conducting a study to gather information from leading DMS vendors to identify available circuit optimization solutions and discuss the most commonly used methods with a focus on future trends. The study is intended to establish a desired list of DMS specification, circuit optimization strategy, and business cases for DMS implementation. Based on the functions discussed in Section 3.3 and the corresponding use cases referenced in Section 3.2, there are information gaps related to the development of use cases for all microgrid controller functions. Microgrid controller functions that were identified to not have an available corresponding use case include power smoothing in grid tied mode, distribution generation and storage management, and isochronous/droop modes of operation in islanded mode. These are significant gaps and need to be overcome. These functions are building blocks for

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[117] Ibid.

[118] *Insights into Advanced Distribution Management Systems.* U.S. Department of Energy: February 2015.

[119] Ibid.

integration and use cases that identify functional requirements should be developed in the near future.

Additionally, many of the use cases reviewed for this project do not follow the IEC template in its entirety. Those use cases may have been developed for other purposes such that sections of the IEC template was omitted if the sections are not necessary for the use cases. With these incomplete use cases, vital information is not available for completely maximizing the concepts discussed. As well, without a properly completed IEC template, scenario diagrams are not available for the use cases.

As discussed in Section 3.5.1, there are existing messages applicable for DERMS but do not consider the involvement of microgrid controllers. Upon examining the requirements associated with microgrid functions in Section 3.4, it becomes clear that many of the functions have essentially the same corresponding architecturally significant messages. For example, nearly every function includes a required step or series of steps to be completed for system verification. The lack of messages specific to microgrid controllers is a gap that should be addressed in the immediate future. Messages should be developed with an architecture that is scalable and extensible so that individual components can be added in modules as users learn about more and more about system behaviors and subsequent needs.

Section 2.1.2 identifies protocols between components depicted in Figure 2.3. The table in Section 2.1.2 uses existing communications protocols, however, some may not be best suited for the solution. As DER technology progresses, there needs to be a standard for data exchange for the purpose of modeling and simulation. This will allow system developers to design controllers that continuously build upon the available technology to compare behaviors to real world operations. Future product development will require a test harness so vendors can certify adherence to newly developed standards without going through the current method of testing that can be costly and acts as a barrier to market. As is the case with any new technology development, vendor buy-in and socialization of these requirements is imperative.

In addition to this, the following four areas need further attention as a scope for future work, to start moving microgrid related technologies into mainstream through supplier and microgrid vendor engagement as well as appropriate standards bodies:

- *Designing for physical and operational safety* – Identifying failure modes and mitigation schemes for generic microgrid architectures as examples / templates to follow for the microgrid vendors. This should include not only the Failure Modes and Effects Analysis but also identification of safety related failures that require mitigation through design, as well as mitigation schemes.
- *Diagnostics and prognostics* – These are special functions of monitoring - to look for unusual operating modes that precede failure of any particular component or subsystem within the microgrid or the microgrid itself. The

diagnostics strategy needs to be at all layers within the microgrid and coordinated at appropriate level of abstraction.

- *Standardization of physical identification and capability description of each class of components within the microgrid* – Electrical distribution network topologies, isolation and safety equipment, generation resources and loads, so that they can be commissioned through generalized operating strategies and truly allow component abstraction while implementing layered control strategies.
- *Standardization of component and subsystem models* – For each class of components within the microgrid - electrical distribution network topologies, isolation and safety equipment, generation resources and loads as well as control algorithms, within popular modeling environments such as OpenDSS or Matlab, so that they can be quickly combined and connected to create typical microgrid configurations for analysis and design.

Section 6: Conclusion

The emphasis of this document is to examine the relationship between DER and the microgrid controller/DERMS as well as the microgrid controller/DERMS and DMS. When some of the distributed resources on the distribution system are configured into microgrids (with the capability to disconnect and operate in an islanded mode), the resources need a microgrid controller to manage their operation and coordination with local loads. DMS refers to an integrated set of control functions for management and optimization of distribution system performance both in normal conditions and in abnormal conditions (response to outages, etc.). Specifically, DMS is a tool that assists the distribution system operators in the control center and in the field with performing their duties while not replacing human judgement and decision making. DMS is also used by engineers for engineering analysis and technicians for trouble-shooting and maintenances as well as managers for oversight and decision making support. DMS is used to optimize efficiency, reliability, and system performance.[120]

DERMS is the managing entity for distributed resources on the distribution system which controls and manages resources like PV, wind generators and other distributed generation such as fuel cells and gas turbines, energy storage systems, and demand response systems. Microgrid controllers are responsible for managing the operation of microgrids – generation and loads – as well as coordinating connection and disconnection of the microgrid from the overall distribution system. During grid-tied mode the microgrid controller is a passive system; however, when the microgrid is in islanded mode the microgrid controller coordinates energy distribution from the DERMs.

The process for this project was initiated by collecting use cases that were relevant to the objectives of the project. Available use cases were compiled and the functions defined in each use case was listed. Once the functions were determined, the use case requirements were mapped to each function and then the data exchanged was identified. Finally messages were mapped to the data exchanged. In the case that a message was not available it was noted and recommended that messages are defined for the gaps in the future.

Functions were broken down into grid tied and islanded functions. Grid tied functions included: connect/disconnect – non-islanding, maximum generation level control, power curtailment, storage management, power smoothing,

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[120] *Distribution Management Systems Planning Guide.* EPRI, Palo Alto, CA: 2013 1024385.

volt/VAR management and power factor, voltage and frequency ride-through, state/status monitoring, and event logging. Islanded functions included: grid-connected to islanding transition (intentional and unintentional), islanding to grid-connected transition, multiple grid configurations/operations, economic dispatch, load and generation following, distributed generation and storage management, power smoothing, load shedding, protection, black start, voltage and frequency control, isochronous/droop modes of operation, power quality and reliability, voltage regulation, dynamic reactive current, user interface and data management, and additions to state/status monitoring. Requirements were derived from these functions based on information available in use cases. The process of defining the requirements brought to light the similarity in the function processes. While the specific requirement for each function differs, they follow a similar process which includes:

1. Microgrid controller sends status - this is a common message
2. Microgrid controller receives commands to do something (generation, state of charge, etc.)
3. Microgrid controller reports exceptions
4. Microgrid controller validates commands it has received.

In the case of the requirements discussed in Section 3.4, the basic messages for status and commands exist. However, for more advanced functionality, e.g. black start or anything with sequencing, messaging is a gap as messages are single actions, including validation of operation, not multiple step. In some situations, this gap can be managed through DMS; however, in the future messages will need to be expanded.

As standards evolve, future microgrid controller development should include an architecture, communications protocols, and standard messages. Until these things are achieved, true interoperability will not be reached.

Appendix A: Additional Functional Requirements

Additional function requirements for grid tied mode.

Function (Grid Tied)	Requirements	Use Case/Scenario Title
Power Curtailment	**DERMS Interface Requirements:** 1. Field Communication Interface: DERMS must provide a downstream communication interface to DER in the field which may be done either via integrated communications or through external communication interfaces. The result is the same with the difference being just an implementation preference. Integrated communications are likely only practical if DER are SCADA-connected, such as may be the case for commercial and utility scale DER. In this case, the DERMS may have standard integrated SCADA capabilities, supporting such protocols as the DNP3 or IEC 61850 MMS. Alternatively, a DERMS may utilize external communication software such as a dedicated SCADA communication interface, an AMI headend, third party cloud service or other. In this case, the DERMS has only a limited number of downstream interfaces and proprietary API's could be utilized if standards do not address these links. In either case, the final downstream communication to the must be an open standard if the process of integrating the many types and brands of products is to be practical and manageable over the long term. 2. Enterprise Integration Interface: The DERMS must have an enterprise integration interface. This interface is used to integrate the DERMS with DMS and other enterprise applications. Each utility's enterprise architecture is unique, with various applications existing and various functionalities grouped within each application. Regardless of how it is packaged, DERMS must have an enterprise interface to allow integration with other applications.	*Requirements for Distributed Energy Resource Management Systems:* *[Frequency-Watt Management]*

Function (Grid Tied)	Requirements	Use Case/Scenario Title
	This enterprise interface shall be standards based, utilizing the IEC Common Information Model (CIM). The global utility industry has been working to develop standard enterprise-level functions and messages for enterprise interactions related to DER management and monitoring. These functions are higher-level, less specific to a single DER, and more oriented to groups of DER as they associate with levels of the power system (e.g., by feeder, by section, by phase). 3. Human Interface: The DERMS shall include a human interface through which users can manage and monitor the overall DER population. Users of various types (various roles within the utility) shall be able to securely access the DERMS with access and permissions that are limited and consistent with their role. DERMS administrators shall be able to setup user access and to flexibly configure the range of permissions extended to each user. 4. Data Storage: The DERMS shall provide secure storage for all user-created settings and for all monitored data. The latter of these is discussed in more detail later in this document and results in large quantities of data. The value of saving this data lies in the analytics that they enable, including after-the fact failure and event analysis, trending, settlement with DER owners, dispute resolution, and optimization of DER management algorithms. In addition, user-created data such as schedules, function curves and full configuration settings shall be storable and reusable. To facilitate this, the DERMS shall provide organized methods for storage of such settings, and search-ability by file name, user, creation date, last date of use, and DER to which the settings have been applied.	

Function (Grid Tied)	Requirements	Use Case/Scenario Title
	DERMS Management Capability Requirements: 5. Time Synchronization: The DERMS shall be capable of synchronizing its sense of time with that of the overall IT system. This may be handled in a number of ways. In most cases, enterprise applications acquire their time from the servers and operating systems (OS) on which they are running, and these servers are synchronized via common means with other onsite systems. Alternatively, this may be accomplished via a time-synchronization message that is received by the DERMS via CIM messages from a time-master (standalone or part of some other application) on the enterprise system. This time reference shall be used by the DERMS for all scheduled activities and for time-stamping of all received or logged data. The DERMS shall be capable of actively managing the time of DER in the field, based on the DERMS time. For devices that are time-settable, the DERMS shall regularly (daily) synchronize the time of each device to the DERMS/system time. In some cases, a DER might have a local time source, such as GPS-based time. In both cases, the DERMS shall compute and record the difference between the DERMS time and the DER time each day and shall provide notifications if this time difference exceeds a pre-determined utility limit. 6. Device Grouping: The DERMS shall support the organization of DER into logical groups and management by group. It shall be possible to form groups and to associate inverters with groups via either the human interface (manual group creation and editing) or through the enterprise integration interface. By way of the enterprise integration interface, other software applications, such as a DMS may determine how DER are to be grouped so that it	

Function (Grid Tied)	Requirements	Use Case/Scenario Title
	can call on these groups in a way that is properly aligned with the other controls involved in overall feeder optimization. In most utility implementations, grouping will be done either by the DMS or at the DERMS, but not both. If grouping is done at the DERMS, then the other enterprise applications such as DMS must be able to discover what groups exist and what devices are members of each group. In the event that DER group creation is performed manually, the means by which the human operator identifies and determines how to group and which DER to assign to each group is out of scope. In other words, the operator can create groups as desired. 7. Curve Creation and Saving: The standard smart inverter functions include a number of configuration settings that are arrays of points. These arrays of x-y point pairs create piece-wise linear "curves" that define how inverters should respond to locally-observable parameters. The DERMS should provide users with a means to create, name, and save a wide range of curves for each of the smart inverter functions that are curve-based. This means would be graphical and easy to use and verify. Accurate curve creation is critical, and these means are intended to help ensure that the intended behavior is achieved. It is not easy to tell what a curve looks like from a text list of x-y points. The DERMS must provide a way to save curves in a file/library that can be drawn from later when overall inverter configurations are produced. It could be, for example, that a utility would have certain curves that are repeatedly used for certain inverter sizes, for certain feeders, or for certain DER asset owners.	

Function (Grid Tied)	Requirements	Use Case/Scenario Title
	8. Schedule Creation and Saving: The IEC standard inverter functions include the ability to download time-based schedules to inverters. The scheduling mechanism is flexible and allows for many different inverter functions to be scheduled. For example, an inverter may have several complete sets of configuration data stored in it. A schedule (daily, weekly, etc.) can be created and sent to the inverter that instructs the inverter to switch from one configuration to the other at times throughout the schedule period. This feature can be useful in minimizing communication system burden in cases when there is a predictable, recurring need for configuration changes. For example, one inverter configuration may be desired during weekday on-peak periods, a second configuration during weekday off-peak periods, and a third configuration on weekends. The DERMS shall provide a GUI through which a user can create, name, and save schedules. The DERMS shall be capable of sending these schedules to groups of inverters. 9. Status Data Logging and Saving: The DERMS shall have a data store interface through which it can log and save monitored inverter data and control actions taken. This may be developed as an internal function of the DERMS or through an enterprise interface to another data-storage application. 10. Optimization and Utility Business Priorities: A range of factors may be taken into account by a DERMS in order to determine how to best utilize DER. Recently, some utilities have used DMS that perform integrated volt/VAR optimization (IVVO). These optimizations involve on-load tap changers (LTCs), capacitors, line	

Function (Grid Tied)	Requirements	Use Case/Scenario Title
	regulators, and switches, along with sensors for monitoring various voltages and power flows. A DMS IVVO seeks to identify the optimal settings for all the distribution controls. The meaning of "optimal," in this case, depends on the business priorities of TPC. 11. Scalability: The DERMS shall be capable of tracking, monitoring, and managing the total number of downstream DER, including those of all scales (utility to residential). Actual utility decisions to integrate the more numerous small systems may be deferred for some time, but DERMS should be scalable/extensible to cover all. In some architectures, a single central DERMS might be used. In this case, the total number of managed DER might be very large, millions potentially. In other architectures, DERMS might be handled at the substation, circuit, or feeder level. In this case, the total number of managed DER might be low, such as tens or hundreds. 12. Security: As the quantity of grid-connected DER increases and the degree of utilization of these resources rises, the communication and control systems become more critical. Given the present environment for high-penetration DER, particularly for solar photovoltaic systems, it is prudent to develop DERMS and the surrounding communication systems with security that is appropriate for critical operations. A comprehensive cyber security plan is outside the scope of this document; however, primary points of consideration are identified in the following sections.	

Function (Grid Tied)	Requirements	Use Case/Scenario Title
	13. Encryption: Communications, both upstream and downstream of the DERMS, shall be encrypted. The recommended standards for these interfaces include extensive cyber-security content. 14. User Security: The DERMS shall provide appropriate user security consistent with utility policy for DMS and other operational applications. This includes physical security for access to the servers and related user interfaces. The DERMS shall support verification of users via credentials, with proper access levels based on staff role (monitoring only, control actions, etc.).	
Voltage and Frequency Ride-Through	See above (Power Curtailment) for detailed requirements	*Requirements for Distributed Energy Resource Management Systems:* *[Low/High Voltage Ride Through]* *And* *[Low/High Frequency Ride Through]*
	See above (Connect/Disconnect – Non Islanding) for detailed requirements	*Enterprise Integration Functions for Distribute Energy Resources:* *[Ride Through Service]*
	See above (Volt-VAR Management and Power Factor) for detailed requirements	*Microgrid Interactive Use Cases #IA-2: Coordination of Volt/VAR Control in Connected Mode Under Normal Operating Conditions*

Function (Grid Tied)	Requirements	Use Case/Scenario Title
Event Logging	See above (Power Curtailment) for detailed requirements	*Requirements for Distributed Energy Resource Management Systems:* *[Status Data Logging and Saving]* *And* *[User Action Logging]*

Additional function requirements for islanded mode.

Function (Islanded)	Requirements	Use Case/Scenario Title
Multiple Grid Configurations/ Operations	**DERMS Interface Requirements:** 1. Field Communication Interface: DERMS must provide a downstream communication interface to DER in the field which may be done either via integrated communications or through external communication interfaces. The result is the same with the difference being just an implementation preference. Integrated communications are likely only practical if DER are SCADA-connected, such as may be the case for commercial and utility scale DER. In this case, the DERMS may have standard integrated SCADA capabilities, supporting such protocols as the DNP3 or IEC 61850 MMS. Alternatively, a DERMS may utilize external communication software such as a dedicated SCADA communication interface, an AMI headend, third party cloud service or other. In this case, the DERMS has only a limited number of downstream interfaces and proprietary API's could be utilized if standards do not address these links. In either case, the final downstream communication to the must be an open standard if the process of integrating the many types and brands of products is to be practical and manageable over the long term. 2. Enterprise Integration Interface: The DERMS must have an enterprise integration interface. This interface is used to integrate the DERMS with DMS and other enterprise applications. Each utility's enterprise architecture is unique, with various applications existing and various functionalities grouped within each application. Regardless of how it is packaged, DERMS must have an enterprise interface to allow integration with other applications. This enterprise interface shall be standards based, utilizing the IEC Common Information Model (CIM). The global utility industry has been working to develop standard enterprise-level functions and messages for enterprise interactions related to DER management and monitoring. These functions are higher-level, less specific to a single DER,	*Requirements for Distributed Energy Resource Management Systems: [Multiple Grid Configurations]*

Function (Islanded)	Requirements	Use Case/Scenario Title
	and more oriented to groups of DER as they associate with levels of the power system (e.g., by feeder, by section, by phase). 3. Human Interface: The DERMS shall include a human interface through which users can manage and monitor the overall DER population. Users of various types (various roles within the utility) shall be able to securely access the DERMS with access and permissions that are limited and consistent with their role. DERMS administrators shall be able to setup user access and to flexibly configure the range of permissions extended to each user. 4. Data Storage: The DERMS shall provide secure storage for all user-created settings and for all monitored data. The latter of these is discussed in more detail later in this document and results in large quantities of data. The value of saving this data lies in the analytics that they enable, including after-the fact failure and event analysis, trending, settlement with DER owners, dispute resolution, and optimization of DER management algorithms. In addition, user-created data such as schedules, function curves and full configuration settings shall be storable and reusable. To facilitate this, the DERMS shall provide organized methods for storage of such settings, and search-ability by file name, user, creation date, last date of use, and DER to which the settings have been applied. **DERMS Management Capability Requirements:** 5. Time Synchronization: The DERMS shall be capable of synchronizing its sense of time with that of the overall IT system. This may be handled in a number of ways. In most cases, enterprise applications acquire their time from the servers and operating systems (OS) on which they are running, and these servers are synchronized via common means with other onsite systems. Alternatively, this may be accomplished via a time-synchronization message that is received by the DERMS via CIM	

Function (Islanded)	Requirements	Use Case/Scenario Title
	messages from a time-master (standalone or part of some other application) on the enterprise system. This time reference shall be used by the DERMS for all scheduled activities and for time-stamping of all received or logged data. The DERMS shall be capable of actively managing the time of DER in the field, based on the DERMS time. For devices that are time-settable, the DERMS shall regularly (daily) synchronize the time of each device to the DERMS/system time. In some cases, a DER might have a local time source, such as GPS-based time. In both cases, the DERMS shall compute and record the difference between the DERMS time and the DER time each day and shall provide notifications if this time difference exceeds a pre-determined utility limit. 6. Device Grouping: The DERMS shall support the organization of DER into logical groups and management by group. It shall be possible to form groups and to associate inverters with groups via either the human interface (manual group creation and editing) or through the enterprise integration interface. By way of the enterprise integration interface, other software applications, such as a DMS may determine how DER are to be grouped so that it can call on these groups in a way that is properly aligned with the other controls involved in overall feeder optimization. In most utility implementations, grouping will be done either by the DMS or at the DERMS, but not both. If grouping is done at the DERMS, then the other enterprise applications such as DMS must be able to discover what groups exist and what devices are members of each group. In the event that DER group creation is performed manually, the means by which the human operator identifies and determines how to group and which DER to assign to each group is out of scope. In other words, the operator can create groups as desired. 7. Curve Creation and Saving: The standard smart inverter functions include a number of configuration settings that are arrays of points. These arrays of x-y point pairs create piece-wise linear “curves” that define how inverters should respond to locally-observable parameters. The DERMS	

Function (Islanded)	Requirements	Use Case/Scenario Title
	should provide users with a means to create, name, and save a wide range of curves for each of the smart inverter functions that are curve-based. This means would be graphical and easy to use and verify. Accurate curve creation is critical, and these means are intended to help ensure that the intended behavior is achieved. It is not easy to tell what a curve looks like from a text list of x-y points. The DERMS must provide a way to save curves in a file/library that can be drawn from later when overall inverter configurations are produced. It could be, for example, that a utility would have certain curves that are repeatedly used for certain inverter sizes, for certain feeders, or for certain DER asset owners. 8. Schedule Creation and Saving: The IEC standard inverter functions include the ability to download time-based schedules to inverters. The scheduling mechanism is flexible and allows for many different inverter functions to be scheduled. For example, an inverter may have several complete sets of configuration data stored in it. A schedule (daily, weekly, etc.) can be created and sent to the inverter that instructs the inverter to switch from one configuration to the other at times throughout the schedule period. This feature can be useful in minimizing communication system burden in cases when there is a predictable, recurring need for configuration changes. For example, one inverter configuration may be desired during weekday on-peak periods, a second configuration during weekday off-peak periods, and a third configuration on weekends. The DERMS shall provide a GUI through which a user can create, name, and save schedules. The DERMS shall be capable of sending these schedules to groups of inverters. 9. Status Data Logging and Saving: The DERMS shall have a data store interface through which it can log and save monitored inverter data and control actions taken. This may be developed as an internal function of the DERMS or through an enterprise interface to another data-storage application.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	10. Optimization and Utility Business Priorities: A range of factors may be taken into account by a DERMS in order to determine how to best utilize DER. Recently, some utilities have used DMS that perform integrated volt/VAR optimization (IVVO). These optimizations involve on-load tap changers (LTCs), capacitors, line regulators, and switches, along with sensors for monitoring various voltages and power flows. A DMS IVVO seeks to identify the optimal settings for all the distribution controls. The meaning of "optimal," in this case, depends on the business priorities of TPC. 11. Scalability: The DERMS shall be capable of tracking, monitoring, and managing the total number of downstream DER, including those of all scales (utility to residential). Actual utility decisions to integrate the more numerous small systems may be deferred for some time, but DERMS should be scalable/extensible to cover all. In some architectures, a single central DERMS might be used. In this case, the total number of managed DER might be very large, millions potentially. In other architectures, DERMS might be handled at the substation, circuit, or feeder level. In this case, the total number of managed DER might be low, such as tens or hundreds. 12. Security: As the quantity of grid-connected DER increases and the degree of utilization of these resources rises, the communication and control systems become more critical. Given the present environment for high-penetration DER, particularly for solar photovoltaic systems, it is prudent to develop DERMS and the surrounding communication systems with security that is appropriate for critical operations. A comprehensive cyber security plan is outside the scope of this document; however, primary points of consideration are identified in the following sections.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	13. Encryption: Communications, both upstream and downstream of the DERMS, shall be encrypted. The recommended standards for these interfaces include extensive cyber-security content. 14. User Security: The DERMS shall provide appropriate user security consistent with utility policy for DMS and other operational applications. This includes physical security for access to the servers and related user interfaces. The DERMS shall support verification of users via credentials, with proper access levels based on staff role (monitoring only, control actions, etc.).	
Load and Generation Following	1. The conditions (settings) for activation of different load managements in the microgrid. 2. The total amount of load connected to each load management means. 3. The amount of common load connected to each group of the load management means. 4. The timing of the information exchange should be consistent with significant changes of the data discussed in the three items above. Many of the underlying operational condition for these data change in near-real time, therefore, the updates of the data exchanges should be in the near-real timeframe. 5. Because of the possibility of multiple load management means in an advanced microgrid, the structure of the exchanged data should support multi-dimensional formats reflecting the relationships between different groups of different load management means.	*Microgrid Interactive Use Cases #IA-6: Updates of the Information on Overlaps of Different Load Management Means Within Microgrids*
	1. Local frequency and voltage fluctuations associated with load fluctuation detected by GI_PAFC Controller. 2. Active and reactive power dispatch command provided by GI_PAFC Controller based on the slope characteristic. 3. PAFC net output acquired by Battery Controller.	*NEDO Local Level Use Case #A2: Autonomous Decentralized Control of Microgrid Which Consists Only of Generating Equipment with Grid-Connected Inverters, Under the Islanding Operation*

Function (Islanded)	Requirements	Use Case/Scenario Title
	4. Power dispatch command for Battery and PCS provided by Battery Controller so that the PAFC net output is maintained at the reference output. 5. PAFC sending-end (local) voltage acquired by GI_PAFC Controller. 6. Reactive power dispatch command provided by GI_PAFC Controller for GC_PAFC and PCS so that the PAFC sending-end voltage is maintained at the reference voltage.	
Load Shedding	1. The setups of the emergency responders of the microgrids aggregated at the microgrid PCCs is made available to DMS by the microgrid EMS. The dependencies of the load and generation on frequency and voltage within the emergency ranges are included in these steps. They also take into account the overlaps of different load management means. 2. Models of the emergency behavior of DER, Microgrids, ES, DR, and DMS applications aggregated at the transmission buses are made available to EMS through transmission bus load model (TBLM) by the DMS TBLM developer. 3. The transmission contingency/security analysis application analyzes the potential situations and recommends preventive measures, including the measures for the distribution system aggregated at the transmission buses. The first iteration of the EMS contingency/security analysis takes into account the currently aggregated in the TBLM load-to-frequency/voltage dependencies, generation- to-frequency/voltage dependencies, the dispatchable load dependencies, the DER capability dependencies, and the overlaps of the different load management means in the expected frequency and voltage ranges. The expected dynamics of the frequency, voltage, and loads at the transmission/distribution demarcation buses are submitted through the TBLM to the DMS. 4. DMS application (Coordination of Emergency Actions) takes the dynamics of the frequency, voltage, and loads obtained from the TBLM as inputs and checks the consistency of these dynamics with the availabilities expected during the following cycle of the contingency analyses. It	*Microgrid Interactive Use Cases #IA-1: Information Support for Coordination of EPS and Microgrid Load Shedding Scheme*

Function (Islanded)	Requirements	Use Case/Scenario Title
	arranges implementation of available/feasible preventive measures including the ones for the microgrids. It also takes into account the near-real-time microgrid conditions, provided by the EMS. If significant preventive measures cannot be implemented, DMS informs the EMS about the actual possibilities through the TBLM, and EMS reiterates the contingency analysis with new constraints. 5. The microgrid EMS applies the expected dynamics of the DMS frequency and voltage to the model of its microgrid and decides what actions to take. The choices include the following: a) The under-frequency load shedding (UFLS)/ under-voltage load shedding (UVLS) is applied to the load within the microgrid, no changes of the setup of the microgrid UFLS/UVLS and DER protection. b) The microgrid UFLS/UVLS is applied to the load within the microgrid with changes of the setup of either the microgrid UFLS/UVLS, or DER protection, or both. c) The microgrid UFLS/UVLS is applied to the interconnection switch at PCC, the microgrid goes into the island mode. d) Other 6. Microgrid EMS coordinates its choices with the DSO/DMS according to the contracts and makes the results available to the DMS 7. DMS updates the TBLM after the execution of the preventive measures. 8. The above cycles are repeated periodically or on an event basis. 9. In the case of an emergency situation, the pre-armed Remedial Actions Schemes, protection schemes, other load management means, and the DMS applications operate according to their setups. 10. After the emergency is mitigated and the DMS is in a steady-state mode, DMS updates the TBLM. 11. The restoration analysis and activities are started. The EMS application analyzes the possibilities of restoration and informs the DMS about existing constraints and desired (available) sequence of restoration on the by-transmission-bus basis.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	12. The microgrid EMS informs DMS about the desired restoration sequences in the microgrid. 13. The DMS application (Coordination of Restorative Actions) optimizes the restoration based on the predefined and requested priorities within the transmission and distribution constraints. 14. Once the cycle of restoration is implemented, DMS updates the TBLM. 15. After the situation has returned to normal, the logs of the preconditions, physical and virtual events are exchanged between the DMS and microgrid for the post-factum analyses. The conditions for emergency operations of the microgrids are changing in near-real time. Hence, the microgrid EMS should update the aggregated at the PCC setups of the emergency responders on by exception basis. 16. The structure of the exchanged data should support multi-dimensional, non-monotonous dependencies, command/request formats, and metrics of data uncertainty. The dependencies should also cover practical emergency ranges of the independent variables. 17. The EMS/DMS applications will use these data in their "what-if" contingency analyses of the DMS operations to derive the near-real time and short-term look-ahead coordination solutions.	
Power Quality and Reliability	**Primary Scenario: Utility Electrical Outage (Feeder Outages – Black Start)** Electrical outage on utility distribution or transmission causes loss of power on all feeders (natural gas supply is not disrupted) Primary Scenario: Natural Gas line or valve failure causes loss of gas supply (in conjunction with loss of electric power) Gas line failure or gas valve failure Primary Scenario: Disaster preparedness planning ensures campus/facility operations following natural disaster	*Use Case 1: Facility Microgrid Reduces Outage Duration Following Natural Disaster Campus* *And* *Use Case 2: Facility Microgrid Reduces Outage Duration Following Natural Disaster Facility* *And*

Function (Islanded)	Requirements	Use Case/Scenario Title
	Regularly scheduled time period for the microgrid/critical circuit test has arrived. Primary Scenario: Resynchronize Campus/Facility Feeder(s) to Utility after Islanding Utility feeder power is restored after an outage and the Energy Manager determines that it is appropriate to reconnect to the utility 1. Total peak load determination will include the high demand needed for motor starts. 2. The microgrid controller shall evaluate the reliability status of campus/facility energy resources including utility provided power. 3. The microgrid controller shall evaluate the reliability status of campus/facility energy resources, including the energy storage systems 4. The microgrid controller shall evaluate the status of the circuit serving critical loads. 5. The microgrid controller shall evaluate outage information. 6. Because a critical facility outage may be reported manually, the Energy Manager shall be able to notify the microgrid controller of a critical load outage. 7. The microgrid controller shall be connected to a UPS to ensure operation during an outage. 8. Microgrid controller shall monitor the grid frequency. 9. Microgrid controller shall be able to trigger configurable commands based on grid frequency (i.e. start diesel generators, command BAS, open breakers) 10. The microgrid controller shall receive current facility data from campus/facility occupancy and load sensing systems 11. The microgrid controller shall receive historic load data from the data historian database.	*Use Case 3: Utility Microgrid Controller Monitors Grid System Status and Exerts Control to Ensure Power Delivery for Critical Facilities*

Function (Islanded)	Requirements	Use Case/Scenario Title
	12. Campus/facility load data shall be transmitted periodically. The default load data rate shall be once every 4 seconds. 13. The microgrid controller shall determine if the microgrid is capable of transitioning to an island. 14. The Microgrid Controller shall determine if on-site diesel generator is capable of supporting the estimated maximum critical facility load. 15. If the microgrid cannot support the estimated critical facility maximum load, then the Microgrid Controller shall issue an alarm to the Energy Manager. 16. The microgrid controller shall input status of critical circuit components. 17. Critical circuit status will be transmitted via the SCADA or other communications system. 18. The microgrid controller shall provide the Energy Manager with the status of the facility's electrical circuit. 19. To meet emergency power and legal requirements, priority levels 1 and 2 shall be deemed critical circuits. 20. The microgrid controller shall allow other circuits to be configured (designated) as critical circuits. 21. The campus/facility sensor system shall transmit facility circuit status for use by the microgrid controller 22. The microgrid controller shall determine if the critical facility circuits are operational (e.g., are energized). 23. In the event that a priority circuit is not operational, the microgrid controller shall generate an Energy Manager alarm. 24. Critical circuit operational alarms shall include an audible alarm in addition to a visual alarm. 25. Critical circuit alarm mechanisms shall include SMS text messages.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	26. In the event that a critical facility circuit is not energized, the microgrid controller shall determine if the critical facilities load can be served by the microgrid. 27. In the event that a critical load is not being served and the microgrid can serve the critical load, the microgrid controller shall execute a series of steps to serve the critical load. 28. The Energy Manager, a member of the facility management team, will be authorized to receive alarms from the microgrid controller. 29. In order to correct faults on critical circuits, the Energy Manager shall be able to remotely command microgrid configuration changes. 30. In order to correct faults on critical circuits, the microgrid controller shall be able to automatically command microgrid configuration changes. 31. The Energy Manager shall be able to disable automatic operation by the microgrid controller. 32. In order to correct critical faults microgrid controller shall control the microgrid to provide power to priority circuits. At a minimum priority circuits are those providing Emergency (EM) power and LR Life-required code functions. 33. In order to correct non-critical faults the microgrid controller shall reconfigure the microgrid to provide power to circuits in a configurable pre-configured order. 34. The default power priority order shall be: ER, LR, OP1, OP2, OP3. 35. To allow for finer control, each priority power group shall have up to ten sub-groups which can be prioritized. 36. Microgrid controller shall be able to monitor and respond to campus/facility voltage measurements 37. The microgrid shall be capable of supporting microgrid generation systems during a utility power outage.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	38. Under future IEEE 1547 requirements, the inverters shall be capable of allowing the PV systems to continue power generation during a utility fault. 39. The microgrid controller shall be configurable to allow management of inverters under future IEEE 1547 requirements. 40. The microgrid controller shall be capable of supporting PV systems during a utility power outage 41. Under future IEEE 1547 requirements, the inverters shall be capable of allowing the Fuel Cell system to continue power generation during a utility fault. 42. The microgrid controller shall be capable of supporting the Fuel Cell systems during a utility power outage. 43. Essential systems in the critical facilities will be protected with UPSs. 44. Microgrid controller shall be able to poll or receive UPS status information. 45. The switchgear separating the microgrid from the distribution system shall be capable of automatically opening to separate the microgrid from the distribution system. 46. The Energy Manager shall be able to able to disable automatic operation of the switchgear connecting the microgrid to the distribution circuit. 47. The switchgear separating the microgrid from the distribution system shall be capable of sending status information to the microgrid controller. 48. The switchgear separating the microgrid from the distribution system shall be capable of sending its position status (open/closed/unknown/error) to the microgrid controller. 49. If an outage still exists after the predetermined time period, then the microgrid controller shall command the microgrid to transition to island mode.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	50. The Energy Manager shall be able to command the microgrid to transition to island mode. 51. The microgrid controller shall input diesel generator statuses. 52. Microgrid controller shall be capable of commanding the backup diesel generators to turn on. 53. The microgrid controller shall be capable of calculating the amount of generation and storage sufficient to power all circuits for a configurable amount of time. 54. The microgrid controller shall determine if the diesel generators, and microgrid generation systems cannot power all circuits for a configurable amount of time. 55. The microgrid controller shall generate an alarm if the generation and storage available cannot power the campus/facility for a predetermined configurable amount of time. 56. If microgrid controller determines there is not enough generation and storage to power all systems for a configurable predetermined amount of time, the microgrid controller shall initiate actions to increase production with the backup diesel generators. 57. In island mode if the diesel generators are not running and if needed, the microgrid controller shall command the backup diesel generator to begin the power up initialization process. 58. The microgrid controller shall use recent monitored load and generation sources to maintain a list of breakers to open to balance the campus/facility. 59. The microgrid controller shall open breakers based on configurable priorities. 60. The microgrid controller shall indicate breaker status to the Energy Manager. 61. The microgrid controller shall indicate recent loading on each breaker circuit.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	62. The microgrid controller shall provide an interface for the Energy Manager to operate the breakers. 63. The microgrid controller shall manage allocation of storage to the non-critical loads in priority order. 64. The microgrid controller shall be able to operate the Energy Storage System to protect it during the time period when campus/facility loads are still connected. 65. The microgrid controller shall be capable of commanding generation devices to serve as the frequency-master. 66. The microgrid controller shall be able to command and monitor microgrid generator operation during normal and Island Mode operation. 67. The microgrid controller shall be able to control microgrid generation system output 68. The microgrid controller shall be able to set microgrid generation system operational modes e.g. load following, fixed output) 69. The microgrid controller shall be able to command switches and inverters to connect/disconnect the microgrid generation system. 70. The microgrid controller shall be able to command the microgrid generation system to operate in a load following mode. 71. The microgrid generation system shall be able to operate in a load following mode. 72. The microgrid controller shall use recent load values for circuits when reclosing breakers to restore loads to the campus/facility microgrid 73. The microgrid controller shall monitor the microgrid system's stability when restoring loads and adjusting generation. 74. The microgrid controller shall maintain a configurable amount of reserve generation when restoring loads to the microgrid to protect	

Function (Islanded)	Requirements	Use Case/Scenario Title
	against already restored loads increasing, or fluctuating generation resources. 75. The microgrid controller shall be able to send commands to the Building Automation System and Lighting Controls to operate in low power or emergency modes. 76. The Building Automation System shall be able to receive commands from microgrid controller. 77. The Building Automation System should be able to receive commands from microgrid controller and trigger changes when loads are later restored. 78. The Lighting System shall be able to receive commands from microgrid controller. 79. The Lighting System should be able to receive commands from microgrid controller and trigger changes when loads are later restored. 80. Microgrid controller shall be able to receive and use PV forecasting data. 81. The microgrid System shall have a PV forecast capability. 82. The microgrid controller shall be able to control and monitor the operation of the microgrid generation system. 83. The microgrid energy manager shall be able to control the microgrid to maximize power restoration or maximize fuel conservation. 84. The energy manager may set diesel generator output at a nominal rating to extend generator fuel capacity if sufficient generation is available from other sources 85. The microgrid controller shall allow the Energy Manager to maximize power restoration or conserve fuel. 86. The microgrid controller shall be capable of selecting power restoration or conserve fuel.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	87. The microgrid controller shall receive current gas supply status data from campus/facility sensors. 88. The microgrid controller shall receive natural gas fueled-generation statuses. 89. Storage devices shall supply power to non-critical devices for a configuration time period in the event of a gas line failure. 90. Unless gas storage is available and the natural gas-fueled generation manufacturers obtain the necessary legal certifications, diesel generators are required to provide emergency power. 91. The storage devices can be commanded to decrease the amount of energy supplied. 92. The storage devices shall be capable of decreasing supply such that momentary power transients do not affect devices. 93. To prevent transient power disruptions, the storage devices shall be able to alarm if insufficient power is available to power the current load for a configurable, pre-specified amount of time. 94. Natural gas-fueled generation shall be restartable following a failure of the gas line. 95. The vendor shall supply natural gas-fueled generation restoration procedures for conditions to include a gas line failure. 96. Natural gas-fueled generators shall be restarted in predetermined order as specified by the manufacturer. 97. Circuit configurations and microgrid status information are available and maintained. 98. Facility manager's participation is obtained as required for disaster preparedness planning and testing of the microgrid. 99. Step by step operational test procedure/test script is documented in writing for testing the microgrid for disaster preparedness planning. 100. The disaster preparedness planning Test script has been validated prior to test execution.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	101. The disaster preparedness planning Test script is consistent with normal safe operation of the microgrid and critical circuit. 102. The disaster preparedness planning expected results are specified for each test step in the disaster preparedness planning test 103. The disaster preparedness planning test step by step instructions are sufficiently detailed to allow the Energy Manager to execute the test. 104. Success and failure criteria are specified for each Grid Connected mode test step in the disaster preparedness planning test. 105. The disaster preparedness planning Test script has been validated prior to test execution. 106. The disaster preparedness planning Test script and is consistent with the safe operation of the microgrid and critical circuit in Island Mode. 107. The facility operations staff can safely inject conditions which cause the microgrid to transition to Island Mode. 108. The Energy Manager has the capability to safely simulate conditions which will cause the microgrid to transition to Island Mode. 109. Success and failure criteria are specified for each Island Mode test step. 110. Test records are stored in the Engineering Data Warehouse or similar repository. 111. Correct action system is available to resolve test issues, off nominal and test failures. 112. When an outage is corrected, microgrid controller shall receive measurements that the utility feeder is restored. 113. Microgrid controller shall report utility feeder uptime to the Energy Manager. 114. Microgrid controller shall report campus/facility loads. 115. Microgrid controller shall report campus/facility generation.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	116. Microgrid controller shall be able to send commands to the microgrid generation control systems 117. The microgrid controller shall be able to command the Building Automation System (BAS) to reduce load. 118. The microgrid controller shall be able to command the Lighting Management System to reduce load. 119. Microgrid controller shall command diesel generator operational modes. 120. Microgrid controller shall control diesel generator switchgear. 121. Microgrid controller shall be able to command diesel generators to operate in a mode to resynchronize the campus/facility circuit to the grid. 122. Diesel generators shall be able to provide a re-synchronization capability. 123. The campus/utility switchgear shall support a re-synchronized connection. 124. Microgrid controller shall receive connection status from campus/utility switchgear. 125. Microgrid controller shall be able to wait a configurable amount of time and then send commands to campus/facility systems to restore the campus/facility to normal utility connected operation 126. Microgrid controller shall be able to open campus/utility switchgear and return to microgrid operation if feeder reconnection fails	
	1. The microgrid EMS should provide the DSO/DMS with the near-real time and short-term look-ahead aggregated at the PCC maximum and minimum operational VAR capabilities as a function of the PCC voltage. These limits are defined by the setups of the Volt/VAR control functions of the VAR sources and other voltage and current limits in the microgrid circuits.	*Microgrid Interactive Use Cases #IA-4: Updates of Capability Curves of the Microgrid's Reactive Power Sources*

Function (Islanded)	Requirements	Use Case/Scenario Title
	2. The microgrid EMS should provide the DSO/DMS with the near-real time and short-term look-ahead aggregated at the PCC maximum and minimum nominal capability limits. These are defined as functions of the reactive power limits versus voltages at the DER terminals regardless of the operational voltage requirements defined by the settings of the Volt/VAR control functions of the DERs. 3. The microgrid EMS should provide the DSO/DMS with the information on the conditions under which the capability curves were derived. 4. The DSO/DMS may request that the microgrid EMS change the volt/VAR control setups of the microgrid VAR sources to meet the DMS VAR support requirements. 5. The microgrid EMS should provide the DSO/DMS with the impacts of the change of the volt/VAR control setup. 6. The conditions for operational VAR capabilities of the microgrid DERs are changing in near-real time. Hence, the microgrid EMS should update the aggregated at the PCC capability curves on by exception basis. 7. The structure of the exchanged data should support multi-dimensional, non-monotonous dependencies, command/request formats, and metrics of data uncertainty. The dependencies should cover practical ranges of the independent variables. 8. The EMS/DMS applications will use these data in their "what-if" studies of the DMS operations to derive the near-real time and short-term look-ahead solutions	
	Demand and Generation Forecast, Generation Scheduling and On-The-Day Review: 1. Past demand record data read by EMS. 2. Demand forecasted by EMS. 3. PCC Reference read by EMS. 4. DER's output reference prepared by EMS. 5. Command output reference to DER.	*Sendai Use Case: Microgrid to Supply Power at Multiple Power Quality Levels (NEDO Sendai Project)*

Function (Islanded)	Requirements	Use Case/Scenario Title
	6. Collection of demand record obtained from customer RTU. 7. Output reference recalculated for DER in consideration of the gap between demand forecast and actual result. 8. Command revised output reference to DER. A-Class Power Quality Supply: 1. Voltage dip detected by IPS, shifts into Battery-Supply Mode and discharges inner storage battery. 2. Grid outage detected by switch 2 and opens. 3. Opening of switch 2 detected by DER. 4. Opening of switch 2 detected by EMS. 5. DER shifts into islanding operation. 6. Command signal sent by EMS to IPS to shift into islanding operation. 7. IPS shifts into DER-Islanding Mode. 8. DER stoppage detected by IPS, enters into Battery-Supply Mode and discharges the inner storage battery. B-Class Power Quality Supply: 1. Voltage dip detected by DVR and generates compensation voltage. 2. Grid outage detected by switch 2 and opens. 3. Opening of switch 2 detected by DER. 4. DER shifts into islanding operation. Automatic Shifting Into Islanding Operation at Grid Outage and Automatic Shifting into Connected Operation at Grid Restoration: 1. Grid outage detected by switch 2 and opens. 2. Grid outage detected by switch 1 and opens. 3. Opening of switch 2 detected by DER. 4. DER shifts into islanding operation.	

Function (Islanded)	Requirements	Use Case/Scenario Title
	5. Grid restoration detected by switch 1 and closes. 6. Voltage and frequency of islanding system synchronized by DER to the grid. 7. Voltage and frequency of grid detected by DER. 8. Voltage and frequency of islanding system detected by DER. 9. Switch 2 closed by DER on confirming the synchronization. 10. Closing of switch 2 detected by DER. 11. DER shifts into grid-connected operation.	
Dynamic Reactive Current	Regardless of where the DER management function is ultimately deployed (a dedicated DERMS or other) it will be necessary for the DER management function to share information with other relevant systems at the utility. What will be needed are extensions to existing standards to support the new DER functions. In terms of communication from the enterprise to devices in the distribution network, there is an expectation that the DERMS will employ either a proprietary vendor interface, or interfaces based on standards such as the IEC 61850 and Distributed Network Protocol (DNP3). What happens inside the DERMS will be up to each vendor and how the DER are managed will also be up to a given vendor. It is neither beneficial nor intended by this initiative to standardize the inner workings and DER optimization algorithms that might be employed inside a DERMS. The focus of this work is to enable communication from the DERMS to the enterprise using utility integration standards, CIM and MultiSpeak.	*Enterprise Integration Functions Test Plan for Distributed Energy Resources, Phase 1:* *[Reactive Power Dispatch of DER Groups]*
User Interface and Data Management	1. Exchange data (microgrid data, real-time area power system operation data, non-real-time microgrid data, real-time microgrid data, real-time market operations data, and real-time microgrid control signals)	*Microgrid Functional Use Case #F-10* *Microgrid User Interface and Data Management*

Appendix B: CIM Messages from Test Cases

DER Group Creation

Example CIM-based XML- createDERGroup

This example XML is for a single group called “Example Name” that contains a single member called “Example DER member: PV array – 1”

```
<?xml version="1.0" encoding="UTF-8"?>
<m:DERGroups xmlns:m="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
file:///C:/Users/PGGR001/Documents/EPRI/067771%20-
%20DER/ExampleProfiles/createDERGroup.xsd">
<m:DERGroup>
<m:name>Example DERGroup Name</m:name>
<!-- for MultiSpeak this would be an objectID not an mRID --
>
<m:mRID>f975be36-a3b6-499c-9518-5e74555b6db9</m:mRID>
<m:DERMember>
<!-- The name, names class, and mRID (objectID for
MultiSpeak, is optional, but one of them MUST be used. This
example[pe uses a
name and a GUID -->
<m:mRID>c1357587-0a37-41a1-bdb6-65af875972a4</m:mRID>
<m:name>Example DER member: PV array - 1</m:name>
</m:DERMember>
</m:DERGroup>
</m:DERGroups>
```

Example CIM-based XML- ReplyDERGroup

```
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2014 rel. 2 sp1
(x64)
(http://www.altova.com)-->
<DERGroups xmlns="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
```

```
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
createDERGroup.xsd">
<DERGroup description="text" comment="text">
<name>Example DERGroup name</name>
<!-- identifier used for the DERGroup, so the requestor can
marry
up to the request that was made -->
<mRID>f975be36-a3b6-499c-9518-5e74555b6db9</mRID>
</DERGroup>
</DERGroups>
```

Querying a DER Group

Example CIM-based XML - getDERGroups

In the GETDER XSD 1 to *n* requests for DER can be made. The request simply needs to pass the identifier for the DERGroup. The response is a listing of all the DERMembers within a group. In the example below, two identifiers are passed, so the expectation is that the members for both groups will be returned in the associated Reply.

```
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2012 rel. 2 (x64)
(http://www.altova.com)-->
<m:DERGroups
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
createDERGroup.xsd"
xmlns:m="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance">
<m:DERGroup>
<m:name>Example DER Group Name</m:name>
<!-- Either mRID needs to be used, or the Names class -->
<m:mRID>8493bde3-afca-411a-8234-d66f550090c3</m:mRID>
</m:DERGroup>
<m:DERGroup>
<m:name>Another example DER Group Name</m:name>
<!-- Either mRID needs to be used, or the Names class -->
<m:mRID>2d4310a5-94dd-4d85-98f1-cf4c14a2b94b</m:mRID>
</m:DERGroup>
</m:DERGroups>
```

Example CIM-Based XML – replyDERGroups

Adding a DER to a Group

Example CIM-based XML changedDERGroup

This is similar to the initial createDERGroup example. The name and ID of this example is the same as the name and ID of the create example, but this adds an additional member to that “Example Group Name” group. Note that the new member is “Example Battery Storage” with its own unique mRID.

```
<?xml version="1.0" encoding="UTF-8"?>
<m:DERGroups xmlns:m="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
file:///C:/Users/PGGR001/Documents/EPRI/067771%20-
%20DER/ExampleProfiles/CreateDERGroup.xsd">
<m:DERGroup>
<m:name>Example Group Name</m:name>
<m:mRID>f975be36-a3b6-499c-9518-5e74555b6db9</m:mRID>
<m:DERMember>
<m:mRID>77075dea-eb70-49fb-ae8b-16848c4767fa</m:mRID>
<m:name>Example Battery storage</m:name>
</m:DERMember>
</m:DERGroup>
</m:DERGroups>
```

Removing a DER from a Group

Example CIM-based XML – executeDERGroup

As noted above, removing a DER member from a DERGroup requires the use of the execute verb and an OperationSet. For clarity, an XML example of the entire CIM-based header is included showing the relationship between header, payload, and the OperationSet.

```
<Header>
<Verb>execute</Verb>
<Noun>OperationSet</Noun>
<Revision>1.0</Revision>
<Timestamp>2014-12-20T09:30:47Z</Timestamp>
<Source>DMS</Source>
<AckRequired>true</AckRequired>
<MessageID>07515735-060C-4125-9A1F-E75AEA19CA76</MessageID>
<CorrelationID>07515735-060C-4125-9A1F-
E75AEA19CA76</CorrelationID>
</Header>
<Payload>
<OperationSet>
<Operation>
<operationID>1</operationID>
<noun>DERGroup</noun>
<verb>delete</verb>
<!—tell receiving system the operation is on the
element, not the object→
<elementOperation>true</elementOperation>
<m:DERGroup>
<!—name/ID of the group to be changed →
```

```
<m:name>Example Group Name</m:name>
<m:mRID>f975be36-a3b6-499c-9518-5e74555b6db9</m:mRID>
<m:DERMember>
<m:mRID>77075dea-eb70-49fb-ae8b-16848c4767fa</m:mRID>
<m:name>Example Battery storage</m:name>
</m:DERMember>
</m:DERGroup>
</m:DERGroups>
</Operation>
</OperationSet>
</Payload>
```

Example CIM-based XML - replyDERGroup

```
<?xml version="1.0" encoding="UTF-8"?>
<ResponseMessage
xmlns = "http://iec.ch/TC57/2011/schema/message"
xmlns:xsi = "http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation = "http://iec.ch/TC57/2011/schema/message
Message.xsd">
<Header>
<Verb>reply</Verb>
<Noun>DERGroup</Noun>
<Revision>1.0</Revision>
<Timestamp>2014-01-21T09:30:48Z</Timestamp>
<Source>DERMS</Source>
<MessageID>F5BA23D4-E1F7-4889-AB2A-CF3ED2BB06C9</MessageID>
<CorrelationID>805C655B-4429-44C4-91C5-
7692810627A7</CorrelationID>
</Header>
<Reply>
<Result>OK</Result>
<Error>
<code>0.0</code>
</Error>
</Reply>
</ResponseMessage>
```

DER Group Deletion

CIM-based Example XML - deleteDERGroup

Note: The example XML for the deletion of a group is the same as for the creation of a group.

The only thing that has changed is the *name* of the end point. Instead of using CreateDERGroup (for CIM-based web services) DeleteDERGroup is used.

Example CIM-based XML - deleteDERGroup

```xml
<?xml version="1.0" encoding="UTF-8"?>
<m:DERGroups xmlns:m="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
file:///C:/Users/PGGR001/Documents/EPRI/067771%20-
%20DER/ExampleProfiles/DeleteDERGroup.xsd">
<m:DERGroup>
<m:name>Example Group Name</m:name>
<!-- for MultiSpeak this would be an objectID not an mRID --
>
<m:mRID>f975be36-a3b6-499c-9518-5e74555b6db9</m:mRID>
</m:DERGroup>
</m:DERGroups>
```

Example CIM-based XML – replyDERGroup

```xml
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2014 rel. 2 sp1
(x64)
(http://www.altova.com)-->
<DERGroups xmlns="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
DERGroup.xsd">
<DERGroup description="text" comment="text">
<name>Example DERGroup name</name>
<!-- identifying used for the DERGroup, so the requestor can
match
to the request that was made -->
<mRID>f975be36-a3b6-499c-9518-5e74555b6db9</mRID>
</DERGroup>
</DERGroups>
```

DER Group Status Monitoring

Example CIM-based XML - getDERGroupStatus

Note: In this example a single request has been used to request status from two different DERGroups, using the mRID as the identifier.

```xml
<?xml version="1.0" encoding="UTF-8"?>
<m:DERGroupStatuses
xmlns:m="http://www.epri.com/2013/DERStatus#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERStatus#
file:///C:/Users/PGGR001/Documents/EPRI/067771%20-
%20DER/ExampleProfiles/GetDERGroupStatus.xsd">
<m:DERGroupStatus>
<m:RequestedCapability>Watts</m:RequestedCapability>
```

```
<m:DERGroup>
<m:name>Example DERGroup Name</m:name>
<!-- an mRID is not required; if one isn't used then Names
class must be used -->
<m:mRID>f975be36-a3b6-499c-9518-5e74555b6db9</m:mRID>
</m:DERGroup>
</m:DERGroupStatus>
<m:DERGroupStatus>
<m:RequestedCapability>ApparentPower</m:RequestedCapability>
<m:DERGroup>
<m:name>Another Example Group Name</m:name>
<!-- mrID is not required, but if it isn't used the Names
class must be used --> <m:mRID>3cc0687b-b530-4924-9542-
f51518e44504</m:mRID>
</m:DERGroup>
</m:DERGroupStatus>
</m:DERGroupStatuses>
```

Example CIM-based XML – replyDERGroupStatus

In this example note that since two statuses were asked for, two were received.

```
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2014 rel. 2 sp1
(x64)
(http://www.altova.com)-->
<DERGroups xmlns="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
CreateDERGroup.xsd">
<DERGroup description="text" comment="text">
<status>
<dateTime>2001-12-17T09:30:47Z</dateTime>
<reason>Because you asked for a status</reason>
<remark>No remark</remark>
<value>0 - OK</value>
</status>
<name>Example DERGroup</name>
<mRID>f975be36-a3b6-499c-9518-5e74555b6db9</mRID>
</DERGroup>
<DERGroup description="text" comment="text">
<status>
<dateTime>2001-12-17T09:30:47Z</dateTime>
<reason>Because you asked for a status</reason>
<remark>No remark</remark>
<value>-1 - Something has gone awry</value>
</status>
<name>Another Example DERGroup name</name>
<mRID>3cc0687b-b530-4924-9542-f51518e44504</mRID>
```

```
</DERGroup>
</DERGroups>
```

DER Group Capabilities Discovery

Example CIM-based XML – getDERGroupCapabilities

See: DERGroupStatus

Note: In CIM-based exchanges this is the same pattern and XSD as for getDERGroupStatus. The contents of the message will change. For instance, there will be no status passed, only the current capabilities and the information object. DERGroupCapabilities will be used instead of DERGroupStatus. See the CIM-based status example from Test 7.

DER Group Dispatch

Example CIM-based XML – createDERGroupDispatch

```
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2014 rel. 2 sp1
(x64)
(http://www.altova.com)-->
<DERGroupDispatches
xmlns="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
createDERGroupDispatch.xsd">
<DERGroupDispatch>
<DERGroup>
<name>Example DERGroup Name</name>
<mRID>b2dd9e07-6062-41b6-b5c8-afe1250beb9e</mRID>
</DERGroup>
<RequestedCapability>
<capabilityType>RealPower</capabilityType>
<value>3.1415901184082031</value>
<capabilityUnits>VA</capabilityUnits>
<capabilityMultiplier>k</capabilityMultiplier>
</RequestedCapability>
</DERGroupDispatch>
</DERGroupDispatches>
```

Example CIM-based XML – replyDERGroupDispatch

This reply simply echoes back the DERGroup name, and assumes a positive result (this requested dispatch occurred) unless an error occurred.

```
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2014 rel. 2 sp1
(x64)
```

```
(http://www.altova.com)-->
<DERGroups xmlns="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
CreateDERGroup.xsd">
<DERGroup description="text" comment="text">
<name>Example DERGroup</name>
<mRID>b2dd9e07-6062-41b6-b5c8-afe1250beb9e </mRID>
</DERGroup>
</DERGroups>
```

DER Forecasting

Example CIM-based XML - createDERGroupForecast

```
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2014 rel. 2 sp1
(x64)
(http://www.altova.com)-->
<DERGroupForecasts
xmlns="http://www.epri.com/2013/DERGroup#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERGroup#
getDERGroupForecast.xsd">
<DERGroupForecast>
<DERGroup>
<name>Example DERGroup name</name>
<!-- identifier for the DERGroup being requested -->
<mRID>b2dd9e07-6062-41b6-b5c8-afe1250beb9e</mRID>
</DERGroup>
<TimeInterval>
<!-- this request is for 3 days -->
<value>3</value>
<TimeUnit>DD</TimeUnit>
</TimeInterval>
<forecastBegin>2014-12-17T09:30:47Z</forecastBegin>
<forecastEnd>2014-12-20T09:30:47Z</forecastEnd>
<RequestedCapability>Watts</RequestedCapability>
<!-- this is the mRID of the requested information object --
>
<mRID>33b4d3ed-b683-495c-8672-e377c2328e94</mRID>
</DERGroupForecast>
</DERGroupForecasts>
```

Example CIM-based XML replyDERGroupForecast

```
<?xml version="1.0" encoding="UTF-8"?>
<!--Sample XML file generated by XMLSpy v2014 rel. 2 sp1
(x64)
(http://www.altova.com)-->
```

```xml
<DERGroupForecasts
xmlns="http://www.epri.com/2013/DERStatus#"
xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance"
xsi:schemaLocation="http://www.epri.com/2013/DERStatus#
DERGroupForecast.xsd">
<DERGroupForecast>
<DERGroup>
<!-- this is the identifier of the DERGroup -->
<mRID>b2dd9e07-6062-41b6-b5c8-afe1250beb9e</mRID>
</DERGroup>
<DERForecastDate>2001-12-17T09:30:47Z</DERForecastDate>
<DERGroupPrediction>
<sequence>0</sequence>
<confidence>95</confidence>
<CapabilityList>
<Watts>
<value>10</value>
<unit>W</unit>
<multipler>k</multipler>
</Watts>
</CapabilityList>
</DERGroupPrediction>
<DERGroupPrediction>
<sequence>1</sequence>
<confidence>95</confidence>
<CapabilityList>
<Watts>
<value>9</value>
<unit>W</unit>
<multipler>k</multipler>
</Watts>
</CapabilityList>
</DERGroupPrediction>
<DERGroupPrediction>
<sequence>2</sequence>
<confidence>90</confidence>
<CapabilityList>
<Watts>
<value>12</value>
<unit>W</unit>
<multipler>k</multipler>
</Watts>
</CapabilityList>
</DERGroupPrediction>
<TimeInterval>
<value>3</value>
<TimeUnit>DD</TimeUnit>
</TimeInterval>
<!-- this is when the forecast begins -->
```

```
<PredictionStartDate>2001-12-
17T09:30:47Z</PredictionStartDate>
<!-- this is the mRID of the response object -->
<mRID>33b4d3ed-b683-495c-8672-e377c2328e94</mRID>
</DERGroupForecast>
</DERGroupForecasts>
```

Program:

Energy Storage and Distributed Generation

3002007067

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